

Environmental Life Cycle Implications of Fuel Oxygenate Production from California Biomass - Appendices

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Contract No. DE-AC36-98-GO10337

APPENDIX A: DETAILED SCENARIO RESULTS

This section provides more detailed data (Table 64 through Table 76) for all 12 scenarios that were modeled (Table 64).

Table 64: Scenarios Studied

<i>Scenario</i>	<i>Biomass Type</i>	<i>Ethanol Production Method</i>	<i>Ligneous Residue Use</i>
1	Rice Straw	Enzyme	Onsite Cogeneration
2	Rice Straw	Enzyme	Biomass Power
3	Rice Straw	Concentrated Acid	Onsite Cogeneration
4	Rice Straw	Concentrated Acid	Biomass Power
5	Forest Residue	Enzyme	Onsite Cogeneration
6	Forest Residue	Enzyme	Biomass Power
7	Forest Residue	Concentrated Acid	Onsite Cogeneration
8	Forest Residue	Concentrated Acid	Biomass Power
9	Chaparral	Enzyme	Onsite Cogeneration
10	Chaparral	Enzyme	Biomass Power
11	Chaparral	Concentrated Acid	Onsite Cogeneration
12	Chaparral	Concentrated Acid	Biomass Power

Data are provided for inflows, outflows, energy consumption, and impact assessment values. The symbols used in the *Articles* column are explained below.

- (r) = Raw material
- (a) = Air emission
- (w) = Water emission
- E = Energy

Table 65: Rice Straw Biomass, Enzyme-Based Ethanol Production, and Lignin Cogeneration

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.09	0%	0%	0%	100%	0%	0%	0.10	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	314	0%	0%	97%	2%	1%	0%	7.08	3%	11%	0%	86%	0%
(r) Iron (Fe, ore)	kg	0.06	0%	0%	1%	99%	0%	0%	0.06	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	46	0%	0%	98%	0%	1%	0%	3.65	1%	97%	0%	2%	0%
(r) Natural Gas (in ground)	kg	434	0%	26%	19%	51%	4%	0%	290	0%	18%	0%	81%	0%
(r) Oil (in ground)	kg	383	0%	0%	12%	66%	22%	0%	277	2%	2%	0%	95%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.02	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.01	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0	0%	7%	33%	17%	43%	0%	0	7%	26%	1%	67%	0%
Water Used (total)	liter	546	0%	0%	7%	91%	2%	0%	36,672	0%	0%	0%	100%	0%
Water: Unspecified Origin	liter	533	0%	0%	7%	93%	0%	0%	521	0%	1%	0%	99%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,521,110	100%	0%	0%	0%	0%	0%	1,606,570	0%	71%	0%	0%	29%
(a) Carbon Dioxide (CO ₂ , fossil)	g	2,929,590	0%	1%	39%	9%	2%	49%	1,406,330	1%	11%	0%	20%	68%
(a) Carbon Monoxide (CO)	g	32,121	98%	0%	1%	1%	0%	0%	1,037	6%	71%	1%	22%	0%
(a) Hydrocarbons (except methane)	g	9,184	0%	1%	75%	24%	0%	0%	2,372	1%	2%	0%	97%	0%
(a) Volatile Organic Compounds (VOC)	g	922	94%	0%	0%	0%	6%	0%	0.00	0%	0%	0%	0%	0%
(a) ethanol	g	0	0%	0%	100%	0%	0%	0%	214	0%	100%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	1,350	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	15	0%	100%	0%	0%	0%
(a) Aldehydes	g	5	0%	7%	89%	3%	2%	0%	0.32	1%	50%	0%	48%	0%
(a) Formaldehyde	g	0.80	0%	1%	48%	14%	37%	0%	0.31	6%	50%	0%	44%	0%
(a) Benzene (C ₆ H ₆)	g	92	0%	46%	30%	17%	6%	0%	39	1%	51%	0%	48%	0%
(a) Hydrogen Chloride (HCl)	g	162	0%	0%	97%	2%	1%	0%	3.83	2%	9%	0%	88%	0%
(a) Hydrogen Fluoride (HF)	g	20	0%	0%	98%	0%	1%	0%	0.08	15%	60%	1%	24%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.94	0%	0%	1%	33%	66%	0%	0.42	10%	12%	1%	78%	0%
(a) Metals (unspecified)	g	0.31	0%	0%	0%	100%	0%	0%	0.32	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	3,452	0%	41%	35%	16%	8%	0%	1,317	1%	51%	0%	48%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	8,449	34%	3%	37%	24%	3%	0%	2,586	7%	10%	1%	83%	0%
(a) Nitrous Oxide (N ₂ O)	g	57	0%	1%	90%	2%	6%	0%	9.06	20%	61%	2%	18%	0%
(a) Particulates (unspecified)	g	7,281	48%	0%	47%	4%	1%	0%	788	3%	62%	0%	35%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	7,447	8%	0%	75%	13%	4%	0%	1,183	1%	15%	0%	84%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	16	0%	0%	4%	20%	76%	0%	4.08	8%	12%	1%	80%	0%
(w) BOD (Biochemical Oxygen Demand)	g	105	0%	0%	10%	12%	78%	0%	22	10%	30%	1%	59%	0%
(w) COD (Chemical Oxygen Demand)	g	761	0%	0%	0%	8%	91%	0%	118	15%	28%	1%	55%	0%
(w) Metals (unspecified)	g	95	0%	0%	0%	97%	3%	0%	97	0%	0%	0%	100%	0%
(w) Hydrocarbons (unspecified)	g	16	0%	0%	0%	99%	1%	0%	16	0%	0%	0%	100%	0%
(w) Phenol (C ₆ H ₆ O)	g	1.97	0%	0%	4%	16%	80%	0%	0.41	10%	11%	1%	78%	0%
(w) Nitrates (NO ₃ ⁻)	g	4.23	0%	0%	27%	73%	0%	0%	13	0%	75%	0%	25%	0%
(w) Oils (unspecified)	g	71	0%	0%	7%	39%	53%	0%	32	4%	4%	0%	91%	0%
(w) Suspended Matter (unspecified)	g	451	0%	0%	4%	14%	82%	0%	87	11%	13%	1%	75%	0%
Waste (nonhazardous)	kg	512	0%	0%	98%	1%	1%	0%	190	0%	97%	0%	3%	0%
E Feedstock Energy	MJ	591	0%	832%	0%	1961%	587%	-3280%	1,065	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	40,007	0%	2%	34%	12%	4%	48%	33,078	1%	23%	0%	16%	60%
E Nonrenewable Energy	MJ	40,525	0%	14%	33%	40%	12%	0%	20,688	1%	15%	0%	84%	0%
E Renewable Energy	MJ	74	0%	1%	51%	39%	8%	0%	13,455	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	40,598	0%	14%	33%	40%	12%	0%	34,143	1%	48%	0%	51%	0%
Eutrophication (water)	g eq. PO ₄	24	0%	0%	2%	12%	86%	0%	5.5	9%	34%	1%	56%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ /yr	72	0%	18%	17%	55%	9%	0%	49	1%	13%	0%	86%	0%
Air Acidification	g eq. H ⁺	422	19%	1%	59%	17%	3%	0%	93	4%	12%	0%	83%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	3,019,698	0%	2%	39%	9%	3%	47%	1,436,798	1%	12%	0%	21%	66%

Table 66: Rice Straw Biomass, Enzyme-Based Ethanol Production, and Lignin Biomass Power

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.09	0%	0%	0%	100%	0%	0%	0.10	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	314	0%	0%	97%	2%	1%	0%	-4.15	-5%	252%	0%	-147%	0%
(r) Iron (Fe, ore)	kg	0.06	0%	0%	1%	99%	0%	0%	0.06	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	46	0%	0%	98%	0%	1%	0%	3.72	1%	97%	0%	2%	0%
(r) Natural Gas (in ground)	kg	434	0%	26%	19%	51%	4%	0%	372	0%	36%	0%	64%	0%
(r) Oil (in ground)	kg	383	0%	0%	12%	66%	22%	0%	278	2%	3%	0%	95%	0%
(r) Phosphate Rock (in ground)	kg	0.00	0%	0%	0%	0%	0%	0%	0.02	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0.00	0%	0%	0%	0%	0%	0%	0.01	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.00	0%	7%	33%	17%	43%	0%	-0.00041	-1%	109%	0%	-8%	0%
Water Used (total)	liter	546	0%	0%	7%	91%	2%	0%	36,671	0%	0%	0%	100%	0%
Water: Unspecified Origin	liter	533	0%	0%	7%	93%	0%	0%	520	0%	1%	0%	99%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,521,110	100%	0%	0%	0%	0%	0%	1,532,090	0%	69%	0%	0%	31%
(a) Carbon Dioxide (CO ₂ , fossil)	g	2,929,590	0%	1%	39%	9%	2%	49%	1,578,910	1%	21%	0%	18%	60%
(a) Carbon Monoxide (CO)	g	32,121	98%	0%	1%	1%	0%	0%	2,146	3%	86%	0%	11%	0%
(a) Hydrocarbons (except methane)	g	9,184	0%	1%	75%	24%	0%	0%	2,198	1%	-6%	0%	105%	0%
(a) Volatile Organic Compounds (VOC)	g	922	94%	0%	0%	0%	6%	0%	0.00	0%	0%	0%	0%	0%
(a) Ethanol	g	8.81E-07	0%	0%	100%	0%	0%	0%	2,030	0%	100%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	54	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	0.002	0%	100%	0%	0%	0%
(a) Aldehydes	g	4.99	0%	7%	89%	3%	2%	0%	0.44	1%	64%	0%	35%	0%
(a) Formaldehyde	g	0.80	0%	1%	48%	14%	37%	0%	0.57	3%	73%	0%	24%	0%
(a) Benzene (C ₆ H ₆)	g	92	0%	46%	30%	17%	6%	0%	69	0%	73%	0%	27%	0%
(a) Hydrogen Chloride (HCl)	g	162	0%	0%	97%	2%	1%	0%	4.08	2%	15%	0%	83%	0%
(a) Hydrogen Fluoride (HF)	g	20	0%	0%	98%	0%	1%	0%	0.11	11%	71%	1%	17%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.94	0%	0%	1%	33%	66%	0%	0.42	9%	13%	1%	77%	0%
(a) Metals (unspecified)	g	0.31	0%	0%	0%	100%	0%	0%	0.32	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	3,452	0%	41%	35%	16%	8%	0%	2,367	1%	73%	0%	27%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	8,449	34%	3%	37%	24%	3%	0%	3,014	6%	23%	0%	71%	0%
(a) Nitrous Oxide (N ₂ O)	g	57	0%	1%	90%	2%	6%	0%	33	5%	89%	0%	5%	0%
(a) Particulates (unspecified)	g	7,281	48%	0%	47%	4%	1%	0%	1,412	2%	79%	0%	20%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	7,447	8%	0%	75%	13%	4%	0%	996	2%	-1%	0%	99%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	16	0%	0%	4%	20%	76%	0%	4.09	8%	13%	1%	79%	0%
(w) BOD (Biochemical Oxygen Demand)	g	105	0%	0%	10%	12%	78%	0%	22	10%	31%	1%	59%	0%
(w) COD (Chemical Oxygen Demand)	g	761	0%	0%	0%	8%	91%	0%	121	15%	30%	1%	54%	0%
(w) Metals (unspecified)	g	95	0%	0%	0%	97%	3%	0%	97	0%	0%	0%	100%	0%
(w) Hydrocarbons (unspecified)	g	16	0%	0%	0%	99%	1%	0%	16	0%	0%	0%	100%	0%
(w) Phenol (C ₆ H ₆ O)	g	1.97	0%	0%	4%	16%	80%	0%	0.42	10%	12%	1%	77%	0%
(w) Nitrates (NO ₃ -)	g	4.23	0%	0%	27%	73%	0%	0%	13	0%	75%	0%	25%	0%
(w) Oils (unspecified)	g	71	0%	0%	7%	39%	53%	0%	32	4%	5%	0%	91%	0%
(w) Suspended Matter (unspecified)	g	451	0%	0%	4%	14%	82%	0%	88	11%	15%	1%	74%	0%
Waste (nonhazardous)	kg	512	0%	0%	98%	1%	1%	0%	341	0%	98%	0%	2%	0%
E Feedstock Energy	MJ	591	0%	832%	0%	1961%	587%	-3280%	1,065	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	40,007	0%	2%	34%	12%	4%	48%	36,139	1%	29%	0%	15%	55%
E Nonrenewable Energy	MJ	40,525	0%	14%	33%	40%	12%	0%	24,392	1%	28%	0%	71%	0%
E Renewable Energy	MJ	74	0%	1%	51%	39%	8%	0%	12,812	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	40,598	0%	14%	33%	40%	12%	0%	37,204	1%	52%	0%	47%	0%
Eutrophication (water)	g eq. PO ₄	24	0%	0%	2%	12%	86%	0%	5.60	9%	34%	1%	55%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ /yr	72	0%	18%	17%	55%	9%	0%	59	1%	27%	0%	72%	0%
Air Acidification	g eq. H ⁺	422	19%	1%	59%	17%	3%	0%	97	4%	15%	0%	80%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	3,019,698	0%	2%	39%	9%	3%	47%	1,638,881	1%	23%	0%	18%	58%

Table 67: Rice Straw Biomass, Conc. Acid-Based Ethanol Production, and Lignin Cogeneration

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.08	0%	0%	0%	100%	0%	0%	0.09	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	282	0%	0%	97%	2%	1%	0%	8.21	2%	31%	0%	67%	0%
(r) Iron (Fe, ore)	kg	0.06	0%	0%	1%	99%	0%	0%	0.06	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	42	0%	0%	98%	0%	1%	0%	46	0%	100%	0%	0%	0%
(r) Natural Gas (in ground)	kg	391	0%	26%	19%	51%	4%	0%	567	0%	62%	0%	38%	0%
(r) Oil (in ground)	kg	345	0%	0%	12%	66%	22%	0%	249	2%	2%	0%	96%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.046	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.012	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.00015	0%	7%	33%	17%	43%	0%	7.66E-05	4%	56%	0%	39%	0%
Water Used (total)	liter	491	0%	0%	7%	91%	2%	0%	38,940	0%	15%	0%	85%	0%
Water: Unspecified Origin	liter	480	0%	0%	7%	93%	0%	0%	477	0%	2%	0%	98%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,521,110	100%	0%	0%	0%	0%	0%	1,354,290	0%	68%	0%	0%	32%
(a) Carbon Dioxide (CO ₂ , fossil)	g	2,637,810	0%	1%	39%	9%	2%	49%	1,979,070	1%	43%	0%	13%	43%
(a) Carbon Monoxide (CO)	g	32,049	98%	0%	1%	1%	0%	0%	1,449	5%	81%	0%	14%	0%
(a) Hydrocarbons (except methane)	g	8,269	0%	1%	75%	24%	0%	0%	2,634	1%	21%	0%	79%	0%
(a) Volatile Organic Compounds (VOC)	g	917	95%	0%	0%	0%	5%	0%	0	0%	0%	0%	0%	0%
(a) Ethanol	g	7.93E-07	0%	0%	100%	0%	0%	0%	0	0%	0%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	146	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	437	0%	100%	0%	0%	0%
(a) Aldehydes	g	4.49	0%	7%	89%	3%	2%	0%	1.12	0%	87%	0%	12%	0%
(a) Formaldehyde	g	0.72	0%	1%	48%	14%	37%	0%	1.06	2%	87%	0%	11%	0%
(a) Benzene (C ₆ H ₆)	g	83	0%	46%	30%	17%	6%	0%	142	0%	88%	0%	12%	0%
(a) Hydrogen Chloride (HCl)	g	146	0%	0%	97%	2%	1%	0%	4.17	2%	25%	0%	73%	0%
(a) Hydrogen Fluoride (HF)	g	18	0%	0%	98%	0%	1%	0%	0.16	7%	82%	1%	10%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.85	0%	0%	1%	33%	66%	0%	0.36	11%	8%	1%	80%	0%
(a) Metals (unspecified)	g	0.28	0%	0%	0%	100%	0%	0%	0.29	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	3,108	0%	41%	35%	16%	8%	0%	4,968	0%	88%	0%	11%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	7,890	36%	3%	35%	23%	3%	0%	3,407	5%	38%	0%	56%	0%
(a) Nitrous Oxide (N ₂ O)	g	51	0%	1%	90%	2%	6%	0%	16	11%	79%	1%	9%	0%
(a) Particulates (unspecified)	g	6,902	50%	0%	45%	3%	1%	0%	3,846	1%	93%	0%	6%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	6,767	9%	0%	74%	13%	4%	0%	1,294	1%	30%	0%	69%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	14	0%	0%	4%	20%	76%	0%	3.52	9%	8%	1%	83%	0%
(w) BOD (Biochemical Oxygen Demand)	g	95	0%	0%	10%	12%	78%	0%	17	13%	15%	1%	71%	0%
(w) COD (Chemical Oxygen Demand)	g	685	0%	0%	0%	8%	91%	0%	94	19%	17%	1%	62%	0%
(w) Metals (unspecified)	g	86	0%	0%	0%	97%	3%	0%	87	0%	0%	0%	100%	0%
(w) Hydrocarbons (unspecified)	g	14	0%	0%	0%	99%	1%	0%	15	0%	0%	0%	100%	0%
(w) Phenol (C ₆ H ₆ O)	g	1.77	0%	0%	4%	16%	80%	0%	0.36	11%	6%	1%	82%	0%
(w) Nitrates (NO ₃ -)	g	3.81	0%	0%	27%	73%	0%	0%	22	0%	86%	0%	14%	0%
(w) Oils (unspecified)	g	64	0%	0%	7%	39%	53%	0%	29	4%	4%	0%	91%	0%
(w) Suspended Matter (unspecified)	g	406	0%	0%	4%	14%	82%	0%	78	12%	11%	1%	75%	0%
Waste (nonhazardous)	kg	461	0%	0%	98%	1%	1%	0%	253	0%	98%	0%	2%	0%
E Feedstock Energy	MJ	532	0%	832%	0%	1961%	587%	-3280%	959	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	36,023	0%	2%	34%	12%	4%	48%	44,967	1%	49%	0%	11%	40%
E Nonrenewable Energy	MJ	36,489	0%	14%	33%	40%	12%	0%	34,153	1%	53%	0%	46%	0%
E Renewable Energy	MJ	66	0%	1%	51%	39%	8%	0%	11,774	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	36,555	0%	14%	33%	40%	12%	0%	45,926	1%	65%	0%	34%	0%
Eutrophication (water)	g eq. PO ₄	21	0%	0%	2%	12%	86%	0%	5.60	9%	40%	1%	50%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ /yr	65	0%	18%	17%	55%	9%	0%	80	0%	52%	0%	48%	0%
Air Acidification	g eq. H ⁺	388	21%	1%	57%	17%	3%	0%	115	4%	35%	0%	61%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	2,718,943	0%	2%	39%	9%	3%	47%	2,088,355	1%	45%	0%	13%	41%

Table 68: Rice Straw Biomass, Conc. Acid-Based Ethanol Production, and Lignin Biomass Power

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.084	0%	0%	0%	100%	0%	0%	0.087	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	282	0%	0%	97%	2%	1%	0%	0.49	40%	-1064%	3%	1120%	0%
(r) Iron (Fe, ore)	kg	0.056	0%	0%	1%	99%	0%	0%	0.058	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	42	0%	0%	98%	0%	1%	0%	46	0%	100%	0%	0%	0%
(r) Natural Gas (in ground)	kg	391	0%	26%	19%	51%	4%	0%	706	0%	70%	0%	30%	0%
(r) Oil (in ground)	kg	345	0%	0%	12%	66%	22%	0%	250	2%	2%	0%	95%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.046	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.012	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.0002	0%	7%	33%	17%	43%	0%	-0.0003	-1%	113%	0%	-12%	0%
Water Used (total)	liter	491	0%	0%	7%	91%	2%	0%	38,940	0%	15%	0%	85%	0%
Water: Unspecified Origin	liter	480	0%	0%	7%	93%	0%	0%	477	0%	2%	0%	98%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,521,110	100%	0%	0%	0%	0%	0%	1,349,980	0%	68%	0%	0%	32%
(a) Carbon Dioxide (CO ₂ , fossil)	g	2,637,810	0%	1%	39%	9%	2%	49%	2,298,370	1%	51%	0%	11%	37%
(a) Carbon Monoxide (CO)	g	32,049	98%	0%	1%	1%	0%	0%	2,539	3%	89%	0%	8%	0%
(a) Hydrocarbons (except methane)	g	8,269	0%	1%	75%	24%	0%	0%	2,561	1%	18%	0%	81%	0%
(a) Volatile Organic Compounds (VOC)	g	917	95%	0%	0%	0%	5%	0%	0.00	0%	0%	0%	0%	0%
(a) Ethanol	g	7.93E-07	0%	0%	100%	0%	0%	0%	1,860	0%	100%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	37	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	0.41	0%	100%	0%	0%	0%
(a) Aldehydes	g	4.49	0%	7%	89%	3%	2%	0%	1.43	0%	90%	0%	10%	0%
(a) Formaldehyde	g	0.72	0%	1%	48%	14%	37%	0%	1.47	1%	90%	0%	8%	0%
(a) Benzene (C ₆ H ₆)	g	83	0%	46%	30%	17%	6%	0%	194	0%	91%	0%	9%	0%
(a) Hydrogen Chloride (HCl)	g	146	0%	0%	97%	2%	1%	0%	4.58	2%	31%	0%	66%	0%
(a) Hydrogen Fluoride (HF)	g	17.91	0%	0%	98%	0%	1%	0%	0.21	5%	86%	0%	8%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.85	0%	0%	1%	33%	66%	0%	0.37	11%	10%	1%	79%	0%
(a) Metals (unspecified)	g	0.28	0%	0%	0%	100%	0%	0%	0.29	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	3,108	0%	41%	35%	16%	8%	0%	6,735	0%	91%	0%	8%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	7,890	36%	3%	35%	23%	3%	0%	4,053	4%	48%	0%	47%	0%
(a) Nitrous Oxide (N ₂ O)	g	51	0%	1%	90%	2%	6%	0%	39	5%	91%	0%	4%	0%
(a) Particulates (unspecified)	g	6,902	50%	0%	45%	3%	1%	0%	4,394	1%	94%	0%	6%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	6,767	9%	0%	74%	13%	4%	0%	1,171	1%	22%	0%	76%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	14	0%	0%	4%	20%	76%	0%	3.55	9%	8%	1%	82%	0%
(w) BOD (Biochemical Oxygen Demand)	g	95	0%	0%	10%	12%	78%	0%	17	13%	17%	1%	69%	0%
(w) COD (Chemical Oxygen Demand)	g	685	0%	0%	0%	8%	91%	0%	98	18%	20%	1%	60%	0%
(w) Metals (unspecified)	g	86	0%	0%	0%	97%	3%	0%	88	0%	0%	0%	100%	0%
(w) Hydrocarbons (unspecified)	g	14	0%	0%	0%	99%	1%	0%	15	0%	0%	0%	100%	0%
(w) Phenol (C ₆ H ₆ O)	g	1.77	0%	0%	4%	16%	80%	0%	0.36	11%	7%	1%	81%	0%
(w) Nitrates (NO ₃ ⁻)	g	3.81	0%	0%	27%	73%	0%	0%	22	0%	86%	0%	14%	0%
(w) Oils (unspecified)	g	64	0%	0%	7%	39%	53%	0%	29	4%	5%	0%	91%	0%
(w) Suspended Matter (unspecified)	g	406	0%	0%	4%	14%	82%	0%	79	12%	13%	1%	74%	0%
Waste (nonhazardous)	kg	461	0%	0%	98%	1%	1%	0%	406	0%	99%	0%	1%	0%
E Feedstock Energy	MJ	532	0%	832%	0%	1961%	587%	-3280%	959	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	36,023	0%	2%	34%	12%	4%	48%	51,245	1%	55%	0%	9%	35%
E Nonrenewable Energy	MJ	36,489	0%	14%	33%	40%	12%	0%	40,942	1%	61%	0%	38%	0%
E Renewable Energy	MJ	66	0%	1%	51%	39%	8%	0%	11,262	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	36,555	0%	14%	33%	40%	12%	0%	52,204	1%	69%	0%	30%	0%
Eutrophication (water)	g eq. PO ₄	21	0%	0%	2%	12%	86%	0%	5.69	9%	41%	1%	49%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ /yr	65	0%	18%	17%	55%	9%	0%	96	0%	60%	0%	40%	0%
Air Acidification	g eq. H ⁺	388	21%	1%	57%	17%	3%	0%	125	3%	41%	0%	56%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	2,718,943	0%	2%	39%	9%	3%	47%	2,451,787	1%	53%	0%	11%	35%

Table 69: Forest Residue Biomass, Enzyme-Based Ethanol Production, and Lignin Cogeneration

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.10	0%	0%	0%	100%	0%	0%	0.11	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	344	0%	0%	96%	2%	1%	0%	-9.18	-6%	179%	0%	-73%	0%
(r) Iron (Fe, ore)	kg	0.069	0%	0%	1%	99%	0%	0%	0.071	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	51	0%	0%	98%	0%	1%	0%	3.49	2%	95%	0%	2%	0%
(r) Natural Gas (in ground)	kg	477	0%	26%	19%	51%	4%	0%	247	1%	-6%	0%	105%	0%
(r) Oil (in ground)	kg	427	2%	0%	11%	65%	22%	0%	314	5%	2%	0%	92%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.025	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.006	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.00019	3%	7%	32%	16%	42%	0%	-0.0006	-2%	108%	0%	-6%	0%
Water Used (total)	liter	600	0%	0%	7%	90%	2%	0%	43,988	0%	9%	0%	91%	0%
Water: Unspecified Origin	liter	585	0%	0%	7%	93%	0%	0%	570	0%	1%	0%	99%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,887,770	100%	0%	0%	0%	0%	0%	1,925,160	0%	73%	0%	0%	27%
(a) Carbon Dioxide (CO ₂ , fossil)	g	3,237,431	1%	1%	38%	9%	2%	48%	1,361,190	4%	-4%	0%	23%	77%
(a) Carbon Monoxide (CO)	g	71,698	99%	0%	0%	0%	0%	0%	1,275	16%	64%	0%	20%	0%
(a) Hydrocarbons (except methane)	g	10,096	0%	1%	75%	24%	0%	0%	2,213	2%	-16%	0%	114%	0%
(a) Volatile Organic Compounds (VOC)	g	59	0%	0%	0%	0%	100%	0%	0	0%	0%	0%	0%	0%
(a) Ethanol	g	9.66E-07	0%	0%	100%	0%	0%	0%	207	0%	100%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	325	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	1,620	0%	100%	0%	0%	0%
(a) Aldehydes	g	5.48	0%	7%	89%	3%	2%	0%	-0.02	-65%	1043%	-2%	-876%	0%
(a) Formaldehyde	g	0.91	3%	1%	47%	14%	36%	0%	0.23	23%	10%	1%	66%	0%
(a) Benzene (C ₆ H ₆)	g	101	0%	46%	30%	17%	6%	0%	16	4%	-33%	0%	128%	0%
(a) Hydrogen Chloride (HCl)	g	178	0%	0%	96%	2%	1%	0%	4.18	7%	5%	0%	89%	0%
(a) Hydrogen Fluoride (HF)	g	22	0%	0%	98%	0%	1%	0%	0.08	43%	30%	1%	25%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	1.08	5%	0%	0%	31%	63%	0%	0.53	22%	10%	1%	67%	0%
(a) Metals (unspecified)	g	0.34	0%	0%	0%	100%	0%	0%	0.35	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	15,931	76%	10%	8%	4%	2%	0%	564	7%	-30%	0%	123%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	8,340	26%	4%	41%	27%	3%	0%	2,561	19%	-12%	1%	92%	0%
(a) Nitrous Oxide (N ₂ O)	g	65	3%	1%	87%	2%	6%	0%	7.02	75%	-2%	2%	25%	0%
(a) Particulates (unspecified)	g	12,783	67%	0%	30%	2%	1%	0%	891	8%	58%	0%	34%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	7,515	0%	0%	82%	14%	4%	0%	982	5%	-15%	0%	111%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	18	3%	0%	4%	19%	74%	0%	5.01	19%	10%	1%	71%	0%
(w) BOD (Biochemical Oxygen Demand)	g	119	3%	0%	10%	11%	76%	0%	28	23%	26%	1%	51%	0%
(w) COD (Chemical Oxygen Demand)	g	867	4%	0%	0%	8%	88%	0%	163	33%	22%	1%	44%	0%
(w) Metals (unspecified)	g	105	0%	0%	0%	97%	3%	0%	107	0%	0%	0%	99%	0%
(w) Hydrocarbons (unspecified)	g	17	0%	0%	0%	99%	1%	0%	18	0%	0%	0%	100%	0%
(w) Phenol (C ₆ H ₆ O)	g	2.23	3%	0%	4%	15%	77%	0%	0.53	23%	10%	1%	67%	0%
(w) Nitrates (NO ₃ ⁻)	g	4.64	0%	0%	27%	73%	0%	0%	14	0%	74%	0%	26%	0%
(w) Oils (unspecified)	g	80	3%	0%	7%	38%	52%	0%	37	10%	4%	0%	86%	0%
(w) Suspended Matter (unspecified)	g	513	3%	0%	3%	13%	80%	0%	113	26%	11%	1%	63%	0%
Waste (nonhazardous)	kg	562	0%	0%	98%	1%	1%	0%	15	4%	49%	0%	47%	0%
E Feedstock Energy	MJ	648	0%	832%	0%	1961%	587%	-3280%	1,168	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	44,275	1%	2%	33%	12%	4%	48%	33,288	2%	14%	0%	17%	66%
E Nonrenewable Energy	MJ	44,842	1%	14%	33%	40%	12%	0%	18,748	4%	-6%	0%	102%	0%
E Renewable Energy	MJ	81	0%	1%	51%	39%	8%	0%	15,708	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	44,923	1%	14%	33%	40%	12%	0%	34,456	2%	42%	0%	55%	0%
Eutrophication (water)	g eq. PO ₄	27	3%	0%	2%	12%	83%	0%	7.00	22%	28%	1%	49%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ /yr	80	1%	18%	17%	55%	9%	0%	46	3%	-3%	0%	100%	0%
Air Acidification	g eq. H ⁺	422	11%	2%	64%	19%	4%	0%	87	14%	-13%	0%	98%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	3,592,002	8%	2%	36%	8%	2%	43%	1,375,204	4%	-4%	0%	24%	76%

Table 70: Forest Residue Biomass, Enzyme-Based Ethanol Production, and Lignin Biomass Power

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.10	0%	0%	0%	100%	0%	0%	0.11	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	344	0%	0%	96%	2%	1%	0%	-3.49	-17%	309%	-1%	-191%	0%
(r) Iron (Fe, ore)	kg	0.069	0%	0%	1%	99%	0%	0%	0.071	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	51	0%	0%	98%	0%	1%	0%	3.64	2%	96%	0%	2%	0%
(r) Natural Gas (in ground)	kg	477	0%	26%	19%	51%	4%	0%	433	1%	40%	0%	60%	0%
(r) Oil (in ground)	kg	427	2%	0%	11%	65%	22%	0%	315	5%	3%	0%	92%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.025	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.006	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.00019	3%	7%	32%	16%	42%	0%	-0.00042	-2%	111%	0%	-9%	0%
Water Used (total)	liter	600	0%	0%	7%	90%	2%	0%	43,989	0%	9%	0%	91%	0%
Water: Unspecified Origin	liter	585	0%	0%	7%	93%	0%	0%	571	0%	1%	0%	99%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,887,770	100%	0%	0%	0%	0%	0%	1,830,090	0%	72%	0%	0%	28%
(a) Carbon Dioxide (CO ₂ , fossil)	g	3,237,431	1%	1%	38%	9%	2%	48%	1,822,980	3%	23%	0%	17%	57%
(a) Carbon Monoxide (CO)	g	71,698	99%	0%	0%	0%	0%	0%	2,321	9%	80%	0%	11%	0%
(a) Hydrocarbons (except methane)	g	10,096	0%	1%	75%	24%	0%	0%	2,459	2%	-5%	0%	103%	0%
(a) Volatile Organic Compounds (VOC)	g	59	0%	0%	0%	0%	100%	0%	0	0%	0%	0%	0%	0%
(a) Ethanol	g	9.66E-07	0%	0%	100%	0%	0%	0%	2,450	0%	100%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	16	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	0.17	0%	100%	0%	0%	0%
(a) Aldehydes	g	5.48	0%	7%	89%	3%	2%	0%	0.56	2%	68%	0%	30%	0%
(a) Formaldehyde	g	0.91	3%	1%	47%	14%	36%	0%	0.72	7%	72%	0%	21%	0%
(a) Benzene (C ₆ H ₆)	g	101	0%	46%	30%	17%	6%	0%	85	1%	75%	0%	24%	0%
(a) Hydrogen Chloride (HCl)	g	178	0%	0%	96%	2%	1%	0%	4.71	6%	16%	0%	79%	0%
(a) Hydrogen Fluoride (HF)	g	22	0%	0%	98%	0%	1%	0%	0.15	23%	62%	1%	14%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	1.08	5%	0%	0%	31%	63%	0%	0.54	22%	11%	1%	66%	0%
(a) Metals (unspecified)	g	0.34	0%	0%	0%	100%	0%	0%	0.35	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	15,931	76%	10%	8%	4%	2%	0%	2,906	1%	75%	0%	24%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	8,340	26%	4%	41%	27%	3%	0%	3,664	14%	22%	0%	64%	0%
(a) Nitrous Oxide (N ₂ O)	g	65	3%	1%	87%	2%	6%	0%	37	14%	81%	0%	5%	0%
(a) Particulates (unspecified)	g	12,783	67%	0%	30%	2%	1%	0%	1,457	5%	74%	0%	21%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	7,515	0%	0%	82%	14%	4%	0%	1,126	4%	-1%	0%	96%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	18	3%	0%	4%	19%	74%	0%	5.09	18%	11%	1%	70%	0%
(w) BOD (Biochemical Oxygen Demand)	g	119	3%	0%	10%	11%	76%	0%	29	22%	27%	1%	50%	0%
(w) COD (Chemical Oxygen Demand)	g	867	4%	0%	0%	8%	88%	0%	167	32%	24%	1%	43%	0%
(w) Metals (unspecified)	g	105	0%	0%	0%	97%	3%	0%	107	0%	0%	0%	99%	0%
(w) Hydrocarbons (unspecified)	g	17	0%	0%	0%	99%	1%	0%	18	0%	0%	0%	100%	0%
(w) Phenol (C ₆ H ₆ O)	g	2.23	3%	0%	4%	15%	77%	0%	0.54	23%	10%	1%	66%	0%
(w) Nitrates (NO ₃ -)	g	4.64	0%	0%	27%	73%	0%	0%	14	0%	74%	0%	26%	0%
(w) Oils (unspecified)	g	80	3%	0%	7%	38%	52%	0%	37	10%	4%	0%	85%	0%
(w) Suspended Matter (unspecified)	g	513	3%	0%	3%	13%	80%	0%	115	25%	12%	1%	62%	0%
Waste (nonhazardous)	kg	562	0%	0%	98%	1%	1%	0%	49	1%	84%	0%	14%	0%
E Feedstock Energy	MJ	648	0%	832%	0%	1961%	587%	-3280%	1,168	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	44,275	1%	2%	33%	12%	4%	48%	42,468	2%	33%	0%	14%	52%
E Nonrenewable Energy	MJ	44,842	1%	14%	33%	40%	12%	0%	28,473	3%	30%	0%	67%	0%
E Renewable Energy	MJ	81	0%	1%	51%	39%	8%	0%	15,163	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	44,923	1%	14%	33%	40%	12%	0%	43,637	2%	54%	0%	44%	0%
Eutrophication (water)	g eq. PO ₄	27	3%	0%	2%	12%	83%	0%	7.12	22%	29%	1%	48%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ /yr	80	1%	18%	17%	55%	9%	0%	68	2%	30%	0%	68%	0%
Air Acidification	g eq. H ⁺	422	11%	2%	64%	19%	4%	0%	115	11%	15%	0%	74%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	3,592,002	8%	2%	36%	8%	2%	43%	1,895,491	3%	25%	0%	17%	55%

Table 71: Forest Residue Biomass, Conc. Acid-Based Ethanol Production, and Lignin Cogeneration

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.083	0%	0%	0%	100%	0%	0%	0.087	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	281	0%	0%	96%	2%	1%	0%	7.90	7%	23%	0%	69%	0%
(r) Iron (Fe, ore)	kg	0.056	0%	0%	1%	99%	0%	0%	0.058	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	41	0%	0%	98%	0%	1%	0%	45	0%	100%	0%	0%	0%
(r) Natural Gas (in ground)	kg	390	0%	26%	19%	51%	4%	0%	455	0%	53%	0%	47%	0%
(r) Oil (in ground)	kg	350	2%	0%	11%	65%	22%	0%	258	6%	2%	0%	92%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.045	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.011	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.00016	3%	7%	32%	16%	42%	0%	0.00007	14%	44%	0%	42%	0%
Water Used (total)	liter	490	0%	0%	7%	90%	2%	0%	38,025	0%	14%	0%	86%	0%
Water: Unspecified Origin	liter	478	0%	0%	7%	93%	0%	0%	474	0%	2%	0%	98%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,887,770	100%	0%	0%	0%	0%	0%	1,658,260	0%	74%	0%	0%	26%
(a) Carbon Dioxide (CO ₂ , fossil)	g	2,647,971	1%	1%	38%	9%	2%	48%	1,742,200	3%	33%	0%	15%	49%
(a) Carbon Monoxide (CO)	g	71,550	99%	0%	0%	0%	0%	0%	1,567	13%	74%	0%	13%	0%
(a) Hydrocarbons (except methane)	g	8,248	0%	1%	75%	24%	0%	0%	2,549	2%	17%	0%	81%	0%
(a) Volatile Organic Compounds (VOC)	g	48	0%	0%	0%	0%	100%	0%	0	0%	0%	0%	0%	0%
(a) Ethanol	g	7.89E-07	0%	0%	100%	0%	0%	0%	0	0%	0%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	55	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	552	0%	100%	0%	0%	0%
(a) Aldehydes	g	4.48	0%	7%	89%	3%	2%	0%	0.81	2%	81%	0%	17%	0%
(a) Formaldehyde	g	0.74	3%	1%	47%	14%	35%	0%	0.80	7%	78%	0%	15%	0%
(a) Benzene (C ₆ H ₆)	g	83	0%	46%	30%	17%	6%	0%	101	1%	83%	0%	17%	0%
(a) Hydrogen Chloride (HCl)	g	145	0%	0%	96%	2%	1%	0%	4.03	7%	18%	0%	75%	0%
(a) Hydrogen Fluoride (HF)	g	18	0%	0%	98%	0%	1%	0%	0.14	24%	64%	1%	11%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.90	6%	0%	0%	31%	62%	0%	0.44	27%	6%	1%	66%	0%
(a) Metals (unspecified)	g	0.28	0%	0%	0%	100%	0%	0%	0.29	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	15,236	80%	8%	7%	3%	2%	0%	3,593	1%	83%	0%	16%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	7,211	30%	3%	39%	25%	3%	0%	3,327	15%	27%	0%	58%	0%
(a) Nitrous Oxide (N ₂ O)	g	53	4%	1%	86%	2%	6%	0%	16	32%	58%	1%	9%	0%
(a) Particulates (unspecified)	g	12,017	72%	0%	26%	2%	1%	0%	3,852	2%	92%	0%	6%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	6,141	0%	0%	81%	14%	4%	0%	1,299	4%	28%	0%	68%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	15	4%	0%	4%	19%	73%	0%	4.11	23%	6%	1%	71%	0%
(w) BOD (Biochemical Oxygen Demand)	g	98	4%	0%	9%	11%	75%	0%	21	30%	13%	1%	56%	0%
(w) COD (Chemical Oxygen Demand)	g	714	5%	0%	0%	8%	87%	0%	130	41%	12%	1%	45%	0%
(w) Metals (unspecified)	g	86	0%	0%	0%	97%	3%	0%	87	0%	0%	0%	99%	0%
(w) Hydrocarbons (unspecified)	g	14	0%	0%	0%	99%	1%	0%	14	0%	0%	0%	100%	0%
(w) Phenol (C ₆ H ₆ O)	g	1.84	4%	0%	4%	15%	77%	0%	0.44	28%	5%	1%	66%	0%
(w) Nitrates (NO ₃ ⁻)	g	3.79	0%	0%	27%	73%	0%	0%	21	0%	86%	0%	14%	0%
(w) Oils (unspecified)	g	66	3%	0%	7%	38%	52%	0%	31	12%	4%	0%	84%	0%
(w) Suspended Matter (unspecified)	g	422	4%	0%	3%	13%	79%	0%	96	30%	8%	1%	61%	0%
Waste (nonhazardous)	kg	459	0%	0%	98%	1%	1%	0%	94	1%	93%	0%	6%	0%
E Feedstock Energy	MJ	529	0%	832%	0%	1961%	587%	-3280%	954	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	36,225	1%	2%	33%	12%	4%	48%	41,222	2%	43%	0%	11%	43%
E Nonrenewable Energy	MJ	36,688	1%	14%	33%	40%	12%	0%	28,881	3%	43%	0%	54%	0%
E Renewable Energy	MJ	66	1%	1%	51%	39%	8%	0%	13,295	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	36,754	1%	14%	33%	40%	12%	0%	42,176	2%	61%	0%	37%	0%
Eutrophication (water)	g eq. PO ₄	22	4%	0%	2%	12%	82%	0%	6.59	24%	33%	1%	42%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ /yr	65	1%	18%	17%	55%	9%	0%	68	2%	42%	0%	56%	0%
Air Acidification	g eq. H ⁺	354	14%	2%	63%	19%	4%	0%	113	11%	27%	0%	61%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	2,984,411	9%	2%	35%	8%	2%	43%	1,822,680	3%	35%	0%	15%	47%

Table 72: Forest Residue Biomass, Conc. Acid-Based Ethanol Production, and Lignin Biomass Power

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.083	0%	0%	0%	100%	0%	0%	0.087	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	281	0%	0%	96%	2%	1%	0%	-8.91	-7%	168%	0%	-61%	0%
(r) Iron (Fe, ore)	kg	0.056	0%	0%	1%	99%	0%	0%	0.058	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	41	0%	0%	98%	0%	1%	0%	45	0%	100%	0%	0%	0%
(r) Natural Gas (in ground)	kg	390	0%	26%	19%	51%	4%	0%	688	0%	69%	0%	31%	0%
(r) Oil (in ground)	kg	350	2%	0%	11%	65%	22%	0%	259	6%	2%	0%	91%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.045	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.011	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.00016	3%	7%	32%	16%	42%	0%	-0.0006	-2%	106%	0%	-5%	0%
Water Used (total)	liter	490	0%	0%	7%	90%	2%	0%	38,024	0%	14%	0%	86%	0%
Water: Unspecified Origin	liter	478	0%	0%	7%	93%	0%	0%	473	0%	2%	0%	98%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,887,770	100%	0%	0%	0%	0%	0%	1,581,390	0%	73%	0%	0%	27%
(a) Carbon Dioxide (CO ₂ , fossil)	g	2,647,971	1%	1%	38%	9%	2%	48%	2,266,400	2%	49%	0%	11%	38%
(a) Carbon Monoxide (CO)	g	71,550	99%	0%	0%	0%	0%	0%	2,512	8%	83%	0%	8%	0%
(a) Hydrocarbons (except methane)	g	8,248	0%	1%	75%	24%	0%	0%	2,323	2%	9%	0%	89%	0%
(a) Volatile Organic Compounds (VOC)	g	48	0%	0%	0%	0%	100%	0%	0	0%	0%	0%	0%	0%
(a) Ethanol	g	7.89E-07	0%	0%	100%	0%	0%	0%	2,010	0%	100%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	13	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	0.77	0%	100%	0%	0%	0%
(a) Aldehydes	g	4.48	0%	7%	89%	3%	2%	0%	1.30	1%	89%	0%	10%	0%
(a) Formaldehyde	g	0.74	3%	1%	47%	14%	35%	0%	1.49	4%	88%	0%	8%	0%
(a) Benzene (C ₆ H ₆)	g	83	0%	46%	30%	17%	6%	0%	188	0%	91%	0%	9%	0%
(a) Hydrogen Chloride (HCl)	g	145	0%	0%	96%	2%	1%	0%	4.71	6%	30%	0%	64%	0%
(a) Hydrogen Fluoride (HF)	g	18	0%	0%	98%	0%	1%	0%	0.23	15%	77%	0%	7%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.90	6%	0%	0%	31%	62%	0%	0.45	27%	8%	1%	65%	0%
(a) Metals (unspecified)	g	0.28	0%	0%	0%	100%	0%	0%	0.29	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	15,236	80%	8%	7%	3%	2%	0%	6,537	1%	91%	0%	9%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	7,211	30%	3%	39%	25%	3%	0%	4,093	12%	41%	0%	47%	0%
(a) Nitrous Oxide (N ₂ O)	g	53.15	4%	1%	86%	2%	6%	0%	37	14%	82%	0%	4%	0%
(a) Particulates (unspecified)	g	12,017	72%	0%	26%	2%	1%	0%	4,288	2%	93%	0%	6%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	6,141	0%	0%	81%	14%	4%	0%	993	5%	6%	0%	89%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	15	4%	0%	4%	19%	73%	0%	4.14	22%	7%	1%	70%	0%
(w) BOD (Biochemical Oxygen Demand)	g	98	4%	0%	9%	11%	75%	0%	21	30%	15%	1%	54%	0%
(w) COD (Chemical Oxygen Demand)	g	714	5%	0%	0%	8%	87%	0%	134	40%	15%	1%	44%	0%
(w) Metals (unspecified)	g	86	0%	0%	0%	97%	3%	0%	87	0%	0%	0%	99%	0%
(w) Hydrocarbons (unspecified)	g	14	0%	0%	0%	99%	1%	0%	14	0%	0%	0%	100%	0%
(w) Phenol (C ₆ H ₆ O)	g	1.84	4%	0%	4%	15%	77%	0%	0.44	28%	6%	1%	66%	0%
(w) Nitrates (NO ₃ ⁻)	g	3.79	0%	0%	27%	73%	0%	0%	21	0%	86%	0%	14%	0%
(w) Oils (unspecified)	g	66	3%	0%	7%	38%	52%	0%	31	12%	4%	0%	84%	0%
(w) Suspended Matter (unspecified)	g	422	4%	0%	3%	13%	79%	0%	98	29%	10%	1%	59%	0%
Waste (nonhazardous)	kg	459	0%	0%	98%	1%	1%	0%	95	1%	93%	0%	6%	0%
E Feedstock Energy	MJ	529	0%	832%	0%	1961%	587%	-3280%	954	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	36,225	1%	2%	33%	12%	4%	48%	51,576	2%	55%	0%	9%	35%
E Nonrenewable Energy	MJ	36,688	1%	14%	33%	40%	12%	0%	40,059	2%	59%	0%	39%	0%
E Renewable Energy	MJ	66	1%	1%	51%	39%	8%	0%	12,471	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	36,754	1%	14%	33%	40%	12%	0%	52,530	2%	69%	0%	30%	0%
Eutrophication (water)	g eq. PO ₄	22	4%	0%	2%	12%	82%	0%	6.69	24%	34%	1%	42%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ /yr	65	1%	18%	17%	55%	9%	0%	95	1%	59%	0%	40%	0%
Air Acidification	g eq. H ⁺	354	14%	2%	63%	19%	4%	0%	120	10%	32%	0%	58%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	2,984,411	9%	2%	35%	8%	2%	43%	2,415,189	2%	51%	0%	11%	35%

Table 73: Chaparral Biomass, Enzyme-Based Ethanol Production, and Lignin Cogeneration

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvestin g	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.035	0%	0%	0%	100%	0%	0%	0.036	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	118	1%	0%	96%	2%	1%	0%	-84	-5%	107%	0%	-3%	0%
(r) Iron (Fe, ore)	kg	0.023	0%	0%	1%	99%	0%	0%	0.024	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	17	1%	0%	98%	0%	1%	0%	3.04	17%	82%	0%	1%	0%
(r) Natural Gas (in ground)	kg	165	2%	26%	19%	50%	4%	0%	5.79	244%	-1674%	0%	1530%	0%
(r) Oil (in ground)	kg	160	11%	0%	10%	59%	20%	0%	203	51%	0%	0%	49%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.026	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.006	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.000076	16%	6%	28%	14%	36%	0%	-0.0035	-2%	102%	0%	0%	0%
Water Used (total)	liter	207	1%	0%	7%	89%	2%	0%	13,762	0%	0%	0%	100%	0%
Water: Unspecified Origin	liter	200	0%	0%	7%	93%	0%	0%	191	0%	-1%	0%	101%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,931,340	100%	0%	0%	0%	0%	0%	1,914,160	0%	91%	0%	0%	9%
(a) Carbon Dioxide (CO ₂ , fossil)	g	1,148,478	4%	1%	37%	9%	2%	46%	366,154	93%	-119%	0%	29%	97%
(a) Carbon Monoxide (CO)	g	101,738	100%	0%	0%	0%	0%	0%	2,672	55%	42%	0%	3%	0%
(a) Hydrocarbons (except methane)	g	15,991	78%	0%	16%	5%	0%	0%	-872	-31%	230%	0%	-99%	0%
(a) Volatile Organic Compounds (VOC)	g	20	0%	0%	0%	0%	100%	0%	0	0%	0%	0%	0%	0%
(a) Ethanol	g	3.30E-07	0%	0%	100%	0%	0%	0%	211	0%	100%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	745	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	368	0%	100%	0%	0%	0%
(a) Aldehydes	g	1.89	1%	6%	88%	3%	2%	0%	-1.01	-8%	114%	0%	-6%	0%
(a) Formaldehyde	g	0.36	16%	1%	41%	12%	31%	0%	0.39	86%	1%	0%	13%	0%
(a) Benzene (C ₆ H ₆)	g	35	3%	45%	30%	17%	6%	0%	-24	-19%	149%	0%	-29%	0%
(a) Hydrogen Chloride (HCl)	g	61	1%	0%	96%	2%	1%	0%	2.85	62%	-7%	0%	44%	0%
(a) Hydrogen Fluoride (HF)	g	7.49	1%	0%	98%	0%	1%	0%	0.21	108%	-11%	0%	3%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.48	26%	0%	0%	24%	49%	0%	0.90	85%	2%	0%	14%	0%
(a) Metals (unspecified)	g	0.12	0%	0%	0%	100%	0%	0%	0.12	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	5,839	78%	9%	8%	3%	2%	0%	-714	-34%	167%	0%	-33%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	2,404	13%	4%	48%	32%	3%	0%	1,841	167%	-110%	0%	43%	0%
(a) Nitrous Oxide (N ₂ O)	g	25	16%	1%	76%	2%	5%	0%	9.67	333%	-240%	1%	6%	0%
(a) Particulates (unspecified)	g	21.483	93%	0%	6%	0%	0%	0%	930	46%	43%	0%	11%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	2,610	2%	0%	80%	14%	4%	0%	439	68%	-53%	0%	85%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	7.45	21%	0%	3%	16%	60%	0%	7.43	85%	-1%	0%	16%	0%
(w) BOD (Biochemical Oxygen Demand)	g	50	21%	0%	8%	9%	62%	0%	50	85%	5%	0%	10%	0%
(w) COD (Chemical Oxygen Demand)	g	375	24%	0%	0%	6%	69%	0%	401	91%	3%	0%	6%	0%
(w) Metals (unspecified)	g	36	1%	0%	0%	96%	3%	0%	39	7%	0%	0%	93%	0%
(w) Hydrocarbons (unspecified)	g	5.83	0%	0%	0%	99%	1%	0%	6.15	2%	0%	0%	98%	0%
(w) Phenol (C ₆ H ₆ O)	g	0.94	22%	0%	3%	12%	63%	0%	0.97	86%	2%	0%	13%	0%
(w) Nitrates (NO ₃ ⁻)	g	1.58	0%	0%	27%	73%	0%	0%	11	0%	89%	0%	11%	0%
(w) Oils (unspecified)	g	32	17%	0%	6%	33%	44%	0%	36	68%	1%	0%	31%	0%
(w) Suspended Matter (unspecified)	g	217	22%	0%	3%	11%	64%	0%	223	87%	2%	0%	11%	0%
Waste (nonhazardous)	kg	193	0%	0%	97%	1%	1%	0%	-57	-7%	111%	0%	-4%	0%
E Feedstock Energy	MJ	221	0%	832%	0%	1961%	587%	-3280%	399	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	15,889	6%	2%	32%	11%	3%	46%	14,693	35%	0%	0%	13%	51%
E Nonrenewable Energy	MJ	16,081	6%	14%	31%	38%	11%	0%	2,895	179%	-304%	0%	225%	0%
E Renewable Energy	MJ	29	3%	1%	50%	38%	8%	0%	12,197	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	16,110	6%	14%	31%	38%	11%	0%	15,092	34%	22%	0%	43%	0%
Eutrophication (water)	g eq. PO ₄	12	23%	0%	1%	10%	66%	0%	13	82%	9%	0%	9%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ / yr	28	5%	18%	16%	53%	9%	0%	11	66%	-106%	0%	140%	0%
Air Acidification	g eq. H ⁺	136	6%	2%	68%	20%	4%	0%	54	141%	-95%	0%	54%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	1,278,970	12%	2%	34%	8%	2%	42%	354,155	100%	-133%	0%	32%	100%

Table 74: Chaparral Biomass, Enzyme-Based Ethanol Production, and Lignin Biomass Power

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.035	0%	0%	0%	100%	0%	0%	0.036	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	118	1%	0%	96%	2%	1%	0%	-36	-11%	117%	0%	-6%	0%
(r) Iron (Fe, ore)	kg	0.023	0%	0%	1%	99%	0%	0%	0.024	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	17	1%	0%	98%	0%	1%	0%	3.19	16%	83%	0%	1%	0%
(r) Natural Gas (in ground)	kg	165	2%	26%	19%	50%	4%	0%	176	8%	42%	0%	50%	0%
(r) Oil (in ground)	kg	160	11%	0%	10%	59%	20%	0%	205	50%	1%	0%	48%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.026	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.006	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.00008	16%	6%	28%	14%	36%	0%	-0.0016	-4%	105%	0%	-1%	0%
Water Used (total)	liter	207	1%	0%	7%	89%	2%	0%	13,765	0%	0%	0%	100%	0%
Water: Unspecified Origin	liter	200	0%	0%	7%	93%	0%	0%	194	0%	0%	0%	100%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,931,340	100%	0%	0%	0%	0%	0%	1,915,010	0%	91%	0%	0%	9%
(a) Carbon Dioxide (CO ₂ , fossil)	g	1,148,478	4%	1%	37%	9%	2%	46%	890,771	38%	10%	0%	12%	40%
(a) Carbon Monoxide (CO)	g	101,738	100%	0%	0%	0%	0%	0%	3,660	40%	58%	0%	2%	0%
(a) Hydrocarbons (except methane)	g	15,991	78%	0%	16%	5%	0%	0%	288	94%	-295%	0%	301%	0%
(a) Volatile Organic Compounds (VOC)	g	20	0%	0%	0%	0%	100%	0%	0	0%	0%	0%	0%	0%
(a) Ethanol	g	3.30E-07	0%	0%	100%	0%	0%	0%	261	0%	100%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	14	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	0.05	0%	100%	0%	0%	0%
(a) Aldehydes	g	1.89	1%	6%	88%	3%	2%	0%	-0.065	-124%	312%	0%	-88%	0%
(a) Formaldehyde	g	0.36	16%	1%	41%	12%	31%	0%	0.722	47%	46%	0%	7%	0%
(a) Benzene (C ₆ H ₆)	g	35	3%	45%	30%	17%	6%	0%	39	12%	70%	0%	18%	0%
(a) Hydrogen Chloride (HCl)	g	61	1%	0%	96%	2%	1%	0%	3.35	53%	9%	0%	38%	0%
(a) Hydrogen Fluoride (HF)	g	7.49	1%	0%	98%	0%	1%	0%	0.27	83%	14%	0%	3%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.48	26%	0%	0%	24%	49%	0%	0.90	84%	3%	0%	13%	0%
(a) Metals (unspecified)	g	0.12	0%	0%	0%	100%	0%	0%	0.12	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	5,839	78%	9%	8%	3%	2%	0%	1,437	17%	67%	0%	16%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	2,404	13%	4%	48%	32%	3%	0%	3,804	81%	-2%	0%	21%	0%
(a) Nitrous Oxide (N ₂ O)	g	25	16%	1%	76%	2%	5%	0%	57	56%	43%	0%	1%	0%
(a) Particulates (unspecified)	g	21,483	93%	0%	6%	0%	0%	0%	1,690	25%	69%	0%	6%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	2,610	2%	0%	80%	14%	4%	0%	48	627%	-1307%	1%	779%	0%
(w) Ammonia (NH ₄ +, NH ₃ , as N)	g	7.45	21%	0%	3%	16%	60%	0%	7.64	82%	2%	0%	16%	0%
(w) BOD (Biochemical Oxygen Demand)	g	50	21%	0%	8%	9%	62%	0%	51	84%	6%	0%	10%	0%
(w) COD (Chemical Oxygen Demand)	g	375	24%	0%	0%	6%	69%	0%	405	90%	4%	0%	6%	0%
(w) Metals (unspecified)	g	36	1%	0%	0%	96%	3%	0%	39	7%	0%	0%	93%	0%
(w) Hydrocarbons (unspecified)	g	5.83	0%	0%	0%	99%	1%	0%	6.15	2%	0%	0%	98%	0%
(w) Phenol (C ₆ H ₆ O)	g	0.94	22%	0%	3%	12%	63%	0%	0.97	85%	2%	0%	12%	0%
(w) Nitrates (NO ₃ -)	g	1.58	0%	0%	27%	73%	0%	0%	11	0%	89%	0%	11%	0%
(w) Oils (unspecified)	g	32	17%	0%	6%	33%	44%	0%	36	68%	2%	0%	30%	0%
(w) Suspended Matter (unspecified)	g	217	22%	0%	3%	11%	64%	0%	226	87%	3%	0%	11%	0%
Waste (nonhazardous)	kg	193	0%	0%	97%	1%	1%	0%	29	14%	77%	0%	8%	0%
E Feedstock Energy	MJ	221	0%	832%	0%	1961%	587%	-3280%	399	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	15,889	6%	2%	32%	11%	3%	46%	25,227	21%	42%	0%	8%	30%
E Nonrenewable Energy	MJ	16,081	6%	14%	31%	38%	11%	0%	13,705	38%	15%	0%	48%	0%
E Renewable Energy	MJ	29	3%	1%	50%	38%	8%	0%	11,920	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	16,110	6%	14%	31%	38%	11%	0%	25,625	20%	54%	0%	25%	0%
Eutrophication (water)	g eq. PO ₄	12	23%	0%	1%	10%	66%	0%	13	81%	10%	0%	9%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ / yr	28	5%	18%	16%	53%	9%	0%	32	23%	26%	0%	50%	0%
Air Acidification	g eq. H ⁺	136	6%	2%	68%	20%	4%	0%	84	90%	-25%	0%	34%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	1,278,970	12%	2%	34%	8%	2%	42%	938,746	38%	12%	0%	12%	38%

Table 75: Chaparral Biomass, Conc. Acid-Based Ethanol Production, and Lignin Cogeneration

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.031	0%	0%	0%	100%	0%	0%	0.033	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	106	1%	0%	96%	2%	1%	0%	7.11	54%	17%	0%	29%	0%
(r) Iron (Fe, ore)	kg	0.021	0%	0%	1%	99%	0%	0%	0.022	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	16	1%	0%	98%	0%	1%	0%	46	1%	99%	0%	0%	0%
(r) Natural Gas (in ground)	kg	149	2%	26%	19%	50%	4%	0%	253	6%	63%	0%	31%	0%
(r) Oil (in ground)	kg	146	12%	0%	10%	58%	20%	0%	195	53%	1%	0%	46%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.046	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.011	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.00007	17%	6%	27%	14%	36%	0%	0.00010	66%	22%	0%	12%	0%
Water Used (total)	liter	186	1%	0%	7%	89%	2%	0%	17,363	0%	29%	0%	71%	0%
Water: Unspecified Origin	liter	179	0%	0%	7%	93%	0%	0%	184	0%	6%	0%	94%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,931,340	100%	0%	0%	0%	0%	0%	1,814,130	0%	91%	0%	0%	9%
(a) Carbon Dioxide (CO ₂ , fossil)	g	1,036,259	5%	1%	37%	8%	2%	46%	1,129,100	30%	33%	0%	9%	28%
(a) Carbon Monoxide (CO)	g	101,710	100%	0%	0%	0%	0%	0%	4,187	35%	63%	0%	2%	0%
(a) Hydrocarbons (except methane)	g	15,640	80%	0%	15%	5%	0%	0%	1,441	19%	27%	0%	54%	0%
(a) Volatile Organic Compounds (VOC)	g	18	0%	0%	0%	0%	100%	0%	0	0%	0%	0%	0%	0%
(a) Ethanol	g	2.96E-07	0%	0%	100%	0%	0%	0%	0	0%	0%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	46	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	165	0%	100%	0%	0%	0%
(a) Aldehydes	g	1.69	1%	6%	88%	3%	2%	0%	0.55	15%	76%	0%	9%	0%
(a) Formaldehyde	g	0.33	17%	1%	40%	12%	30%	0%	0.78	44%	50%	0%	6%	0%
(a) Benzene (C ₆ H ₆)	g	32	3%	44%	29%	17%	6%	0%	64	7%	83%	0%	10%	0%
(a) Hydrogen Chloride (HCl)	g	55	1%	0%	96%	2%	1%	0%	3.35	53%	13%	0%	34%	0%
(a) Hydrogen Fluoride (HF)	g	6.73	1%	0%	98%	0%	1%	0%	0.28	78%	19%	0%	2%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.44	28%	0%	0%	24%	47%	0%	0.88	86%	1%	0%	12%	0%
(a) Metals (unspecified)	g	0.10	0%	0%	0%	100%	0%	0%	0.11	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	5,707	80%	8%	7%	3%	2%	0%	2,412	10%	81%	0%	9%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	2,189	14%	4%	48%	31%	3%	0%	4,428	69%	14%	0%	16%	0%
(a) Nitrous Oxide (N ₂ O)	g	23	18%	1%	74%	2%	5%	0%	39	83%	15%	0%	1%	0%
(a) Particulates (unspecified)	g	21.337	94%	0%	5%	0%	0%	0%	4,128	10%	87%	0%	2%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	2,349	2%	0%	80%	14%	4%	0%	979	30%	35%	0%	34%	0%
(w) Ammonia (NH ₄ ⁺ , NH ₃ , as N)	g	6.84	23%	0%	3%	15%	59%	0%	7.50	84%	1%	0%	15%	0%
(w) BOD (Biochemical Oxygen Demand)	g	46	23%	0%	8%	9%	60%	0%	49	89%	2%	0%	9%	0%
(w) COD (Chemical Oxygen Demand)	g	346	26%	0%	0%	6%	68%	0%	393	93%	2%	0%	6%	0%
(w) Metals (unspecified)	g	33	1%	0%	0%	96%	3%	0%	35	7%	0%	0%	93%	0%
(w) Hydrocarbons (unspecified)	g	5.23	0%	0%	0%	99%	1%	0%	5.53	2%	0%	0%	98%	0%
(w) Phenol (C ₆ H ₆ O)	g	0.87	24%	0%	3%	12%	61%	0%	0.94	88%	1%	0%	11%	0%
(w) Nitrates (NO ₃ ⁻)	g	1.42	0%	0%	27%	73%	0%	0%	19	0%	94%	0%	6%	0%
(w) Oils (unspecified)	g	29	18%	0%	6%	32%	44%	0%	35	69%	2%	0%	28%	0%
(w) Suspended Matter (unspecified)	g	200	24%	0%	3%	10%	63%	0%	222	88%	2%	0%	10%	0%
Waste (nonhazardous)	kg	173	0%	0%	97%	1%	1%	0%	109	4%	94%	0%	2%	0%
E Feedstock Energy	MJ	199	0%	832%	0%	1961%	587%	-3280%	358	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	14,356	6%	2%	32%	11%	3%	45%	30,875	17%	56%	0%	6%	22%
E Nonrenewable Energy	MJ	14,529	6%	13%	31%	38%	11%	0%	19,220	27%	43%	0%	30%	0%
E Renewable Energy	MJ	26	4%	1%	50%	38%	8%	0%	12,013	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	14,555	6%	13%	31%	38%	11%	0%	31,233	17%	65%	0%	19%	0%
Eutrophication (water)	g eq. PO ₄	11	25%	0%	1%	9%	64%	0%	14	78%	14%	0%	8%	0%
Depletion of Nonrenewable Resources	frac. of reserve*10 ¹⁵ / yr	26	5%	17%	16%	53%	9%	0%	40	18%	46%	0%	35%	0%
Air Acidification	g eq. H ⁺	123	7%	2%	68%	20%	4%	0%	127	60%	19%	0%	21%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	1,163,299	13%	2%	34%	8%	2%	41%	1,191,771	30%	35%	0%	8%	27%

Table 76: Chaparral Biomass, Conc. Acid-Based Ethanol Production, and Lignin Biomass Power

Article	Units	OPTION 1: Total	Biomass Burning	Natural Gas: Production	Methanol: Production	MTBE: Production	MTBE RFG: Production	MTBE RFG: Use	OPTION 2: Total	Biomass Harvesting	Ethanol: Production	Ethanol: Transport	ETBE: Production	ETBE RFG: Use
(r) Bauxite (Al ₂ O ₃ , ore)	kg	0.031	0%	0%	0%	100%	0%	0%	0.033	0%	0%	0%	100%	0%
(r) Coal (in ground)	kg	106	1%	0%	96%	2%	1%	0%	-29	-13%	121%	0%	-7%	0%
(r) Iron (Fe, ore)	kg	0.021	0%	0%	1%	99%	0%	0%	0.022	0%	0%	0%	100%	0%
(r) Limestone (CaCO ₃ , in ground)	kg	16	1%	0%	98%	0%	1%	0%	46	1%	99%	0%	0%	0%
(r) Natural Gas (in ground)	kg	149	2%	26%	19%	50%	4%	0%	851	2%	89%	0%	9%	0%
(r) Oil (in ground)	kg	146	12%	0%	10%	58%	20%	0%	197	53%	2%	0%	45%	0%
(r) Phosphate Rock (in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.046	0%	100%	0%	0%	0%
(r) Potash (K ₂ O, in ground)	kg	0	0%	0%	0%	0%	0%	0%	0.011	0%	100%	0%	0%	0%
(r) Uranium (U, ore)	kg	0.000070	17%	6%	27%	14%	36%	0%	-0.0014	-5%	105%	0%	-1%	0%
Water Used (total)	liter	186	1%	0%	7%	89%	2%	0%	17,362	0%	29%	0%	71%	0%
Water: Unspecified Origin	liter	179	0%	0%	7%	93%	0%	0%	183	0%	5%	0%	95%	0%
(a) Carbon Dioxide (CO ₂ , biomass)	g	1,931,340	100%	0%	0%	0%	0%	0%	1,702,150	0%	91%	0%	0%	9%
(a) Carbon Dioxide (CO ₂ , fossil)	g	1,036,259	5%	1%	37%	8%	2%	46%	2,490,670	14%	70%	0%	4%	13%
(a) Carbon Monoxide (CO)	g	101,710	100%	0%	0%	0%	0%	0%	4,696	31%	67%	0%	2%	0%
(a) Hydrocarbons (except methane)	g	15,640	80%	0%	15%	5%	0%	0%	998	27%	-5%	0%	78%	0%
(a) Volatile Organic Compounds (VOC)	g	18	0%	0%	0%	0%	100%	0%	0	0%	0%	0%	0%	0%
(a) Ethanol	g	3.0E-07	0%	0%	100%	0%	0%	0%	470	0%	100%	0%	0%	0%
(a) Furfural	g	0	0%	0%	0%	0%	0%	0%	6.89	0%	100%	0%	0%	0%
(a) HMF	g	0	0%	0%	0%	0%	0%	0%	0.10	0%	100%	0%	0%	0%
(a) Aldehydes	g	1.69	1%	6%	88%	3%	2%	0%	1.89	4%	93%	0%	3%	0%
(a) Formaldehyde	g	0.33	17%	1%	40%	12%	30%	0%	2.52	13%	85%	0%	2%	0%
(a) Benzene (C ₆ H ₆)	g	32	3%	44%	29%	17%	6%	0%	287	2%	96%	0%	2%	0%
(a) Hydrogen Chloride (HCl)	g	55	1%	0%	96%	2%	1%	0%	5.07	35%	43%	0%	22%	0%
(a) Hydrogen Fluoride (HF)	g	6.73	1%	0%	98%	0%	1%	0%	0.50	44%	54%	0%	1%	0%
(a) Hydrogen Sulfide (H ₂ S)	g	0.44	28%	0%	0%	24%	47%	0%	0.90	84%	3%	0%	12%	0%
(a) Metals (unspecified)	g	0.10	0%	0%	0%	100%	0%	0%	0.11	0%	0%	0%	100%	0%
(a) Methane (CH ₄)	g	5,707	80%	8%	7%	3%	2%	0%	9,949	2%	95%	0%	2%	0%
(a) Nitrogen Oxides (NO _x as NO ₂)	g	2,189	14%	4%	48%	31%	3%	0%	6,199	49%	39%	0%	12%	0%
(a) Nitrous Oxide (N ₂ O)	g	23	18%	1%	74%	2%	5%	0%	73	44%	55%	0%	1%	0%
(a) Particulates (unspecified)	g	21,337	94%	0%	5%	0%	0%	0%	4,808	9%	89%	0%	2%	0%
(a) Sulfur Oxides (SO _x as SO ₂)	g	2,349	2%	0%	80%	14%	4%	0%	322	93%	-96%	0%	104%	0%
(w) Ammonia (NH ₄ +, NH ₃ , as N)	g	6.84	23%	0%	3%	15%	59%	0%	7.56	83%	2%	0%	14%	0%
(w) BOD (Biochemical Oxygen Demand)	g	46	23%	0%	8%	9%	60%	0%	50	87%	4%	0%	9%	0%
(w) COD (Chemical Oxygen Demand)	g	346	26%	0%	0%	6%	68%	0%	403	90%	4%	0%	5%	0%
(w) Metals (unspecified)	g	33	1%	0%	0%	96%	3%	0%	35	7%	0%	0%	92%	0%
(w) Hydrocarbons (unspecified)	g	5.23	0%	0%	0%	99%	1%	0%	5.53	2%	0%	0%	98%	0%
(w) Phenol (C ₆ H ₆ O)	g	0.87	24%	0%	3%	12%	61%	0%	0.95	87%	1%	0%	11%	0%
(w) Nitrates (NO ₃ -)	g	1.42	0%	0%	27%	73%	0%	0%	19	0%	94%	0%	6%	0%
(w) Oils (unspecified)	g	29	18%	0%	6%	32%	44%	0%	35	69%	3%	0%	28%	0%
(w) Suspended Matter (unspecified)	g	200	24%	0%	3%	10%	63%	0%	227	86%	4%	0%	10%	0%
Waste (nonhazardous)	kg	173	0%	0%	97%	1%	1%	0%	104	4%	94%	0%	2%	0%
E Feedstock Energy	MJ	199	0%	832%	0%	1961%	587%	-3280%	358	0%	835%	0%	1138%	-1873%
E Fuel Energy	MJ	14,356	6%	2%	32%	11%	3%	45%	58,339	9%	77%	0%	3%	11%
E Nonrenewable Energy	MJ	14,529	6%	13%	31%	38%	11%	0%	48,218	11%	77%	0%	12%	0%
E Renewable Energy	MJ	26	4%	1%	50%	38%	8%	0%	10,479	0%	100%	0%	0%	0%
E Total Primary Energy	MJ	14,555	6%	13%	31%	38%	11%	0%	58,698	9%	81%	0%	10%	0%
Eutrophication (water)	g eq. PO ₄	11	25%	0%	1%	9%	64%	0%	14	77%	16%	0%	8%	0%
Depletion of Nonrenewable Resources	frac. of reserve*1015/y	26	5%	17%	16%	53%	9%	0%	110	7%	80%	0%	13%	0%
Air Acidification	g eq. H+	123	7%	2%	68%	20%	4%	0%	145	52%	29%	0%	18%	0%
Greenhouse Effect (direct, 100 years)	g eq. CO ₂	1,163,299	13%	2%	34%	8%	2%	41%	2,722,247	13%	72%	0%	4%	12%

APPENDIX B: IMPACT ASSESSMENT

BACKGROUND

Only recently has the LCA tool actually been concerned with the impacts on the environment of a system. By definition, the inventory component of an LCA, still the single focus of many LCA studies, is only concerned with the flows generated by the system (either consumed or emitted), and by definition, do not address the reception issue, i.e., the impacts on the environment.

In the most straightforward and transparent approach to LCI interpretation, the LCI results may be used *as-is* to help identify and prioritize opportunities for pollution prevention or increases in material and energy efficiency for processes within the life cycle. A particular advantage of LCI applied in this way is its comprehensiveness. LCAs help detect the shifting of environmental burdens from one life cycle stage to another (e.g., lower energy consumption during use, achieved at the cost of much higher manufacturing energy consumption), or from one media to another (e.g., lower air emissions at the cost of increased solid waste).

The subsequent stage, LCIA, addresses the issue of how to translate the flows previously compiled into environmental impacts. Some issues viewed as crucial for LCIA are:

- The amount of additional exposure data that would be needed to model actual impacts (as in human health risk assessment) is technically incompatible with the nature of LCA (several hundreds or thousands of processes connected together, each one generating dozens or hundreds of emissions), and does not correspond to its objectives. It should be recognized that LCA is one environmental management tool among several, and that LCA cannot replace a specific environmental impact analysis for a specific site (see Figure 82).
- Since LCIA aims at assessing potential impacts, LCA should not be considered as a predictive tool for assessing the actual impacts associated with a system, but rather as a tool providing comparative results for the functional unit considered. Moreover, the functional unit has often no reference to time or space considerations (which would be needed for predictive models), but is solely related to the function and performance of a system. As the modeling of environmental impacts improves, potential LCIA models should become more and more precise and integrate crucial notions such as thresholds (current approaches are all based on a “less-is-better” approach). Consequently, inventory data collection requirements could gradually increase with new parameters characterizing emissions’ location, flow rate, key attributes of impacted media, etc.
- Existing approaches that result in a limited number of indices are highly controversial. They have been criticized because they do not separate the objective evaluation stage of the environmental impact on scientific grounds from the subjective “valuation” stage in which these impacts are traded off. Using such approaches is very dangerous from an industrial perspective, due to the following reasons:
 - * It tends to favor short-term arbitrary choices while masking their arbitrary nature behind quantitative approaches, which convey more rigor and objectivity than are truly involved. This is incompatible with industrial long-term investment and product design.
 - * The choices made might hide pollution displacement from one media to another or from one step to another.

In numerous cases, results of inventory or impact assessment have been conclusive enough so that no valuation was actually needed. Moreover, very often, the existence of trade-offs is by itself a crucial piece of information.

- For most impact categories, variability and uncertainties about impact potentials make any single numerical “equivalency factor” immediately contradictable and discreditable. Instead, LCIA methods need to be developed in which process data and results are considered in probabilistic terms. As for inventory results, uncertainties should be propagated and communicated to the decision-making audience.

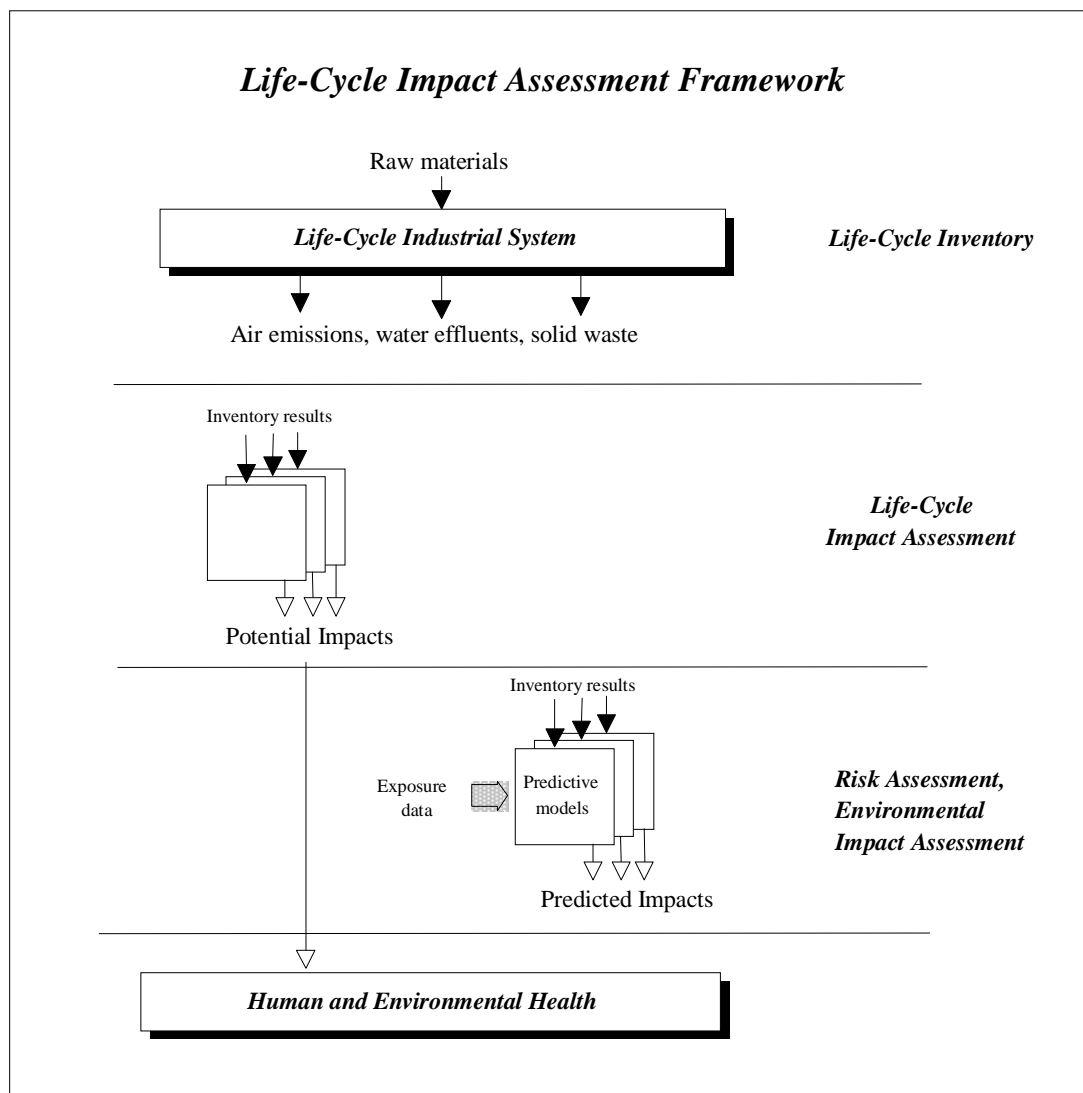


Figure 82: Life Cycle Impact Assessment Framework

OVERVIEW OF LIFE CYCLE IMPACT ASSESSMENT INDICES

Greenhouse Potential

The Greenhouse potential refers to the ability of some atmospheric gases to retain heat that is radiating from the earth. Models have been developed to quantify the contribution made by emissions of various substances to the greenhouse potential. Generally these models provide an indication of the change in the heat radiation absorption of the atmosphere. Global warming potentials (GWPs) have been calculated to compare the emission of different greenhouse gases [1].

The overall result of emission of these gases on the Greenhouse Potential (E) is calculated as follows:

$$E = \sum GWP_i \times m_i$$

where, for a greenhouse gas i ,

m_i is the mass of the gas released (in kg),

GWP_i is its potential impact on global warming.

Greenhouse potential is expressed in grams of CO₂ equivalent.

The following factors are used to calculate the greenhouse potential (Table 77).

Table 77: Greenhouse Gas Potential Factors

<i>Formula</i>	<i>Substance</i>	<i>GWP_i</i>
CO ₂	Carbon dioxide	1
CH ₄	Methane	21
N ₂ O	Nitrous Oxide	310
CCl ₄	Carbon Tetrachloride	1,400
CFCl ₃	CFC 11	4,000

The potential impact on global warming of the gas i can be defined as the ratio between the cumulative radiative force between present and a future time horizon (in this case, 20, 100 and 500 years) as a result of the release of a unit mass of greenhouse gas i now, and an equal emission of the standard gas, carbon dioxide. The calculation of the GWP is based on understanding the fate of the emitted gas and the radiative effect associated with the amount remaining in the atmosphere.

Acidification Potential

Potential acidic deposition (onto soil, vegetation, and water) can be expressed as potential H⁺ equivalents. Potentially acidifying emissions of SO₂, NO_x, and NH_x can be aggregated on the basis of their potential to form H⁺. In the calculation of H⁺ equivalents, it is assumed that one mole SO₂ will produce two moles H⁺, that one mole nitrogen oxide compounds (NO_x) will produce one mole H⁺, and that one mole reduced nitrogen compounds (NH_x) will produce one mole H⁺.

An acidification potential (AP) of a substance is calculated on the basis of the number of H⁺ ions which can be produced per mole (given by the stoichiometry of the oxidation reaction) [2]. However, as emissions are specified in kg rather than in moles, the weight has to be divided by the molecular weight of the substance.

The factors used for acidification potential are listed in Table 78.

Table 78: Acidification Potential Reactions

<i>Formula</i>	<i>Substance</i>	<i>Reaction</i>	<i>AP</i>
SO ₂	Sulfur dioxide	$SO_2 + H_2O + O_3 \rightarrow 2H^+ + SO_4^{2-} + O_2$	32
NO _x	Nitrogen oxides	$NO_2 + OH^- \rightarrow H^+ + NO_3^-$	46
NH ₃	Ammonia	$NH_3 + 2O_2 \rightarrow H^+ + NO_3^- + H_2O$	17
HCl	Hydrochloric acid	$HCl \rightarrow H^+ + Cl^-$	36.5
HF	Hydrogen fluoride	$HF \rightarrow H^+ + F^-$	20

Eutrophication Potential

Eutrophication is the addition of mineral nutrients to the soil or water, which increases production of cell biomass. In both media, the addition of mineral nutrients (N and P) in large quantities result in generally undesirable shifts in the number of species in ecosystems and a reduction in the ecological diversity. In water, it tends to increase algae growth, that eventually die and sink to the deeper layers of the water body. The decomposition of this dead cell biomass requires the consumption of large amounts of oxygen, which can result in the death of other aquatic species, such as fish.

Another form of oxygen deficit may be caused by emissions of organic materials that can bind oxygen. These emissions are generally expressed as the biochemical oxygen demand (BOD) or the COD. The oxygen is mainly consumed by the biological degradation of organic content.

The eutrophication potential (EP) of a substance is calculated on the basis of its potential cell biomass formation. It is calculated in N equivalent, by considering the average ratio of N and P in cell biomass and the oxygen required for the breakdown of this cell biomass. The ratios for N, P, and O₂ are 7, 1, and 142, respectively.

NPs are developed by analogy with the GWP. Therefore, phosphate ions have been chosen as the reference substance. A single index is produced for the eutrophication:

$$\text{eutrophication potential} = \sum_i EP_i \times m_i$$

where m_i is the weight (in kg) of the substance released. The calculated quantity indicates the quantity of a PO₄ emission with the same potential eutrophication effect.

The following classification factors (Table 79) are used for the eutrophication potential (source: CML, Environmental Life Cycle Assessment of Products, Guide - October 1992):

Table 79: Eutrophication Potential Factors

<i>Formula</i>	<i>Substance</i>	<i>EP</i>
PO ₄	Phosphates	1
P	Phosphorous	3.06
N	Nitrogen	0.42
NO _x	Nitrogen Oxides	0.2
NH ₃	Ammonia	0.42
COD	Chemical Oxygen Demand	0.022

Natural Resources Depletion Index

Resource Depletion as an Environmental Issue

Resource depletion can be defined as the decreasing availability of natural resources. The resources considered in this impact are fossil and mineral resources, excluding biotic resources and associated impacts such as species extinction and loss of biodiversity. It is important to recognize that what is addressed in this index is the fact that some resources are depleted, not the fact that their extraction from the environment will generate impacts (e.g., methane emissions from coal mining).

Concepts

Corresponding Inventory Flows

The assessment of natural resources depletion can only be applied to a subset of the LCI flows called elementary flows, i.e., flows that are directly taken from the environment. A coal consumption of 1 kg at the power plant gate does not correspond to an elementary flow. Rather, it corresponds to a consumption of approximately 1.03 kg of coal in the ground, due to the losses in mining, processing, and transportation.

Availability Defined

The notion of availability can be further defined. Natural resources depletion does not consider the availability within the economy, but rather within the “natural” environment. Excluded from this impact are “economic stocks” such as aluminum from aluminum cans or steel from used car bodies. Therefore, the availability is not measured within the whole economy, but only at the economy/environment “boundary.” Furthermore, the availability is concerned with the availability within the primary extraction medium (e.g., iron ore available from the earth’s crust) and not within the entire geosphere (which would include iron available in water bodies, atmosphere, plants, landfills, etc.).

Resource versus Reserve

Once the concept of availability has been defined, the notion of reserve of a resource needs also to be determined. Through the years, geologists, mining engineers, and others operating in the mineral field have used various terms to describe and classify mineral resources. Known resources can be classified from two standpoints: 1) purely geologic or physical/chemical characteristics—such as grade, tonnage, thickness, and depth—of the material in place, and 2) profitability analyses based on costs of extracting and marketing the material in a given economy at a given time. The former constitutes important objective scientific information of the resource and a relatively unchanging foundation upon which the latter economic delineation can be based.

For mineral resources, the reserve chosen for this index is the reserve base as defined by the U.S. Bureau of Mines: “part of an identified resource [3]³² that meets specified minimum physical and chemical criteria related to current mining and production practices, including those for grade, quality thickness, and depth. The reserve base encompasses those parts of the resources that have a reasonable potential for becoming economically available within planning horizons beyond those that assume proven technology and current economics. It includes those resources that are currently economic (reserve), marginally economic (marginal reserves) and currently sub-economic.” By including economic and sub-economic considerations, the reserve base falls between the two extremes of economic reserve and ultimate reserve/resource base.

For fossil fuels (including uranium), the reserve chosen is based on information supplied by the World Energy Council (WEC). In order to be consistent with the reserve base used by the U.S. Bureau of Mines, the reserve chosen for fossil fuels has been defined as the addition of the WEC’s “proved amount in place” (tonnage in place that has been both carefully measured and has also been assessed as exploitable under present and expected local economic conditions with existing available technology) and “estimated additional reserves recoverable” (quantity of the estimated additional amount in place which might become recoverable within foreseeable economic and technological limits).

It should be noted that what matters most in this impact assessment index is the availability of a relative scale allowing comparisons between resources rather than an estimation of the exact size of what is considered available for use. This is linked to the fact that Impact Assessment as performed within an LCA is of a comparative rather than predictive nature. It aims at assessing the relative potential impacts of different alternatives (i.e., natural resource depletion index of A versus B) rather than assessing the actual impacts of a system onto the environment (as it would be done in traditional risk assessment).

Used Index

Once the type reserve is identified, an index can be defined that will relate an inventory flow with the depletion of that resource. The proposed depletion index uses equivalency factors, i.e., each natural resource consumption recorded in the inventory is multiplied by the resource’s weighting factor (or equivalency factor). As described in equation (1) of Figure 83, the total depletion index is then compiled by adding the previous intermediate results for all inventory flows considered.

Several methods can be used to produce the equivalency factors.

³² Opposed to identified resources are undiscovered resources, the existence of which is only postulated.

In the first method described in equation (2), the inverse of reserve (in kg) is used as a weighting factor. Such an index addresses the relative contribution of the LCA system to the depletion of the reserves (the larger the relative contribution, the bigger the index) as well as the size of the reserve (the larger the reserve, the smaller the index). However, it does not address the following problem: how long a given resource will continue to be available (the fact that the reserve is rapidly or slowly being depleted, which is directly related to the notion of sustainability, is not accounted for in this index).

In the second method, described in equation (3), the inverse of remaining years of use is used as a weighting factor. The number of remaining years of use is defined as the reserves divided by the total world-wide production (i.e., extraction). It represents the number of years for which current reserves will suffice at the current production (extraction) level. This index, however, does not correctly account for the size of the reserve: two resources with the same number of years will have the same indices irrespective of whether there are 1 kg or 1 million Mt reserves.

In the third method described in equation (4) and retained as a basis for the index, the inverse of remaining years of use and the reserve size are used as weighting factors. This index addresses both problems that were raised by the first two methods. It should be noted, however, that choosing higher (e.g. cubic) power for the reserve and production could generate a number of similar indices.³³ Since there is no rational basis for doing so, the index has been kept as in equation (4). In order to facilitate the readability of the results, all equivalency factors have been multiplied by 10^{15} (as explained previously, the relative contribution of each resource is what matters most).

$$\begin{aligned}
 (1) \quad Depletion &= \sum_{res} \text{equivalency factor}_{res} \times \text{inventory consumption}_{res} \\
 (2) \quad Depletion &= \sum_{res} \frac{1}{\text{reserve}_{res}} \times \text{inventory consumption}_{res} \\
 (3) \quad Depletion &= \sum_{res} \frac{1}{\text{years}_{res}} \times \text{inventory consumption}_{res} = \sum_{res} \frac{\text{production}_{res}}{\text{reserve}_{res}} \times \text{inventory consumption}_{res} \\
 (4) \quad Depletion &= \sum_{res} \frac{1}{\text{reserve}_{res} \times \text{years}_{res}} \times \text{inventory consumption}_{res} = \sum_{res} \frac{\text{production}_{res}}{(\text{reserve}_{res})^2} \times \text{inventory consumption}_{res}
 \end{aligned}$$

Figure 83: Natural Resource Depletion Impact Equations

³³ It has been shown that in order to keep the index independent of the resource density, that the power of the reserve should be the power of the production plus one, which is the case in equation (4).

APPENDIX C: POTENTIAL CALIFORNIA BIOMASS AVAILABILITY

INTRODUCTION

California is a diverse 100 million-acre area with approximately 70 million acres of wildlands susceptible to wildfires. Another 8 million acres of agriculture land are under cultivation. Currently, California has a growing population of 33 million people, each generating on the average, more than one ton of urban waste annually. The opportunities for creating a new ethanol industry in California rest on diverting wildland wastes from wildfire fuel, agriculture wastes from open-field burning, and urban wastes from being landfilled.

Annually, more and more state, federal, and local regulatory limitations are placed on agriculture-related open-field burning. In addition, the costs and losses associated with wildfires are increasing, with the average annual totals of wildfire suppression costs and losses exceeding \$1 billion in California alone. During peak years, wildfire costs and losses have reached more than \$2 billion. These problems and regulatory efforts to reduce the related environmental impacts are increasing the costs to continue wildlands and agriculture residues burning. The avoided costs of wildfire fuel loading reductions and disposing of agriculture residues using alternatives to open-field burning, offer significant economic and environmental benefits to using the biomass as feedstock for a new biomass-to-ethanol industry.

Thus, California has a major biomass waste disposal problem, annually contributing approximately 43 million tons of forest residues, sawmill residues, agriculture wastes, and urban wood wastes to California's waste streams. In addition, there are an estimated 2 million tons of chaparral burned annually on California wildlands, much of which is contributing to large environmental problems and economic losses.

This Appendix characterizes three scenarios of representative California biomass wastes that could be used as raw material in biomass-to-ethanol facilities:

- Rice straw that could be diverted from open-field burning in the Sacramento Valley.
- Biomass that could be harvested to reduce wildfire fuel loading from Northeastern California forest lands.
- Chaparral that could be harvested rather than burned to protect homes and other high-value environmental and economic assets in Southern California from catastrophic wildfires.
- The following sections:
 - Identify the estimated biomass volumes and related biomass waste disposal problems,
 - Discuss the potential for a new biomass-to-ethanol industry in California,
 - Identify GIS maps of concentrations of biomass throughout the state,
 - Make gross estimates of air pollutant emissions from existing open-field fires and wildfires, and
 - Provide some assumptions and estimates for collection, harvesting, processing, and transportation costs to deliver each biomass type to a potential biomass-to-ethanol facility.

ESTIMATED CALIFORNIA BIOMASS VOLUMES

Biomass can be classified into four categories: agriculture residues, forests and woodlands, chaparral, and urban (this last feedstock is not included in the current study).

Agriculture Residues

There are an estimated 20.5 million BDT of agriculture residues available annually in California. This includes rice, wheat, grass, and other grain straws, orchard prunings, orchard removals, grape prunings, cotton stalks, corn stalks, nutshells, food processing wastes, livestock wastes, and others.

Of the total agricultural residues produced, there are an estimated 1.5 million tons of rice straw produced on approximately 500,000 acres in California. Less than 2% is utilized as a raw material or by-product. The remainder is open-field burned or incorporated back into the soil. Rice straw and other agriculture residues are becoming more expensive to dispose of, as burning becomes less viable. Some of the reasons and related trends are:

- Regulations and statutes are reducing volumes that can be open-field burned.
- Rice straw is the first agriculture residue where reductions in open-field burning are mandated by state law to be no more than 25% of the planted acreage by the year 2001.
- Open-field burning of other agricultural wastes is also being reduced and will probably be eliminated.

Forests and Woodlands

There are an estimated 18 million BDT of forest and woodland biomass available annually in California. These include sawmill residues, logging slash, pre-commercial thinnings, fuel hazard reduction materials, etc. The following are some of the factors that influence forest biomass availability:

- Averages of approximately \$1 billion in costs/losses from wildfires annually, and the long-term trend is for costs and losses to continue to increase. A majority of these costs and losses can be avoided if the fuel loading is reduced by harvesting and transporting for use in a biomass-to-ethanol facility.
- Long-term cumulative increase in biomass fuel per acre (1.3% annually on 14 of California's National Forests) since the post-European settlement.
- New state initiatives to identify high-risk, high-value wildfire areas and partially subsidize the diversion of biomass into commercial applications.

Chaparral

Because there has been little historical research on removal of chaparral for raw material, there is little known of the annual volume of chaparral physically and economically available in California. Depending upon which vegetation types are included, there are between 9 million and 20 million acres of chaparral in California. Most of these lands are covered with mixtures of brush and scrub oak, and are highly volatile fuels for the 10,000 California wildfires that, on average, occur each year. However, very little research has been done and little is known about this source of biomass. Based on limited empirical studies, total volumes of chaparral biomass per acre range from 6 to 51 green tons. Most of this material is not available for collection and processing because of potential environmental impacts, lack of access, and a low cost/benefit return for fuel loading reduction compared to the value of the resources and other assets being protected.

Using the existing empirical studies reflecting 6 to 51 green tons of chaparral per acre and 9 million acres of chaparral lands, there are an estimated 56 million to 459 million green tons of standing biomass on California chaparral lands. However, much of this fuel is on steep slopes with erosive granite soils, and is only available for wildfire consumption. It is not economically viable or environmentally acceptable to conduct clearcut harvesting of chaparral. However, it is viable to use and expand the existing manual harvesting of chaparral projects that are piling and open-field burning chaparral to reduce wildfire fuel loading and protect valuable assets such as homes, people, potable water, and environmentally sensitive areas.

There are two primary sources of existing chaparral collection efforts: 1) creating fuel breaks by hand clearing around high value assets, such as homes, reservoirs and environmentally sensitive wildland areas, and 2) as part of the state's wildland fire protection system, use of inmate crews and other publicly funded conservation crews to construct and maintain fuel breaks. These fuel breaks are used as primary fire suppression lines when wildfires burn through an area. All of the chaparral that is cut by these hand crews is piled and open-field burned, contributing to the air pollution. These manual fuel reduction efforts on chaparral lands are minimal compared to the total volume of excessive fuel loading on the millions of acres of chaparral lands. With additional economic market incentives, such as use of the material in a biomass-to-ethanol facility, and public subsidies to reduce the costs/losses of wildfires, these chaparral-harvesting efforts could be significantly expanded.

Lastly, major concentrations of chaparral are located near the state's population centers in Southern California. These chaparral masses contribute heavily to the fuel loading for large damaging wildfires. Coincidentally, these concentrations are also located in areas that suffer from some of the worst air quality in California, the South Coast Air Basin. Typically large wildfires burn in the summer, when air pollution is the highest. Thus, diversion of chaparral from burning will have a direct beneficial impact on reducing air pollutants during the smoggiest period of the year in Southern California.

The 1997 Annual Report of the Department of Forestry and Fire Protection—Conservation Camp indicates that conservation camp crews located in Southern California reported a total of 35,111 activity person days devoted to Fire Defense Improvements and an additional 2,736 activity person days devoted to the Vegetation Management Program. In accomplishing these activities, crews had the potential to divert significant volumes of chaparral as raw material for a manufacturing product such as ethanol. In addition, expansion of the conservation camp program for fuel load reduction work could result in significantly more material available in the future.

Urban Biomass

There are an estimated 4.5 million BDT of urban biomass available annually in California. These include landscape and right-of-way prunings, tree removals, wood manufacturing product wastes, including furniture, pallet, dunnage, construction lumber residues, demolition materials, etc. Some of the trends that will cause future increases of urban wastes are:

- The annual volume of urban waste is increasing significantly, reflecting large population increases: currently 33 million, projected to reach as high as 50 million by the year 2018.
- A 1990 California statute (B-939) requires cities and counties to divert 50% of the waste materials from landfills to the reuse or recycle sectors by the year 2000. A major portion of this urban waste stream waste is biomass. Based on collection surveys, the biomass ranges from 6%-35% of the waste stream, depending on the geographical area of the state.

Total California Biomass Available

Using the above data, there are an estimated 43 million BDT of biomass available annually in California. In summary, the following conclusions are important to the use of this biomass for manufacturing facilities such as biomass-to-ethanol:

- The biomass is increasing annually, particularly in the urban waste stream and forests.
- Little is known about the volumes of chaparral available for use in biomass-to-ethanol facilities. This is an area needing significantly more research. Because, as referenced above, when large, damaging wildfires burn, they are in the summertime, during the smoggiest time of the calendar year. Thus, diversion of chaparral (from being burned) into a raw material will have a direct beneficial impact on reducing air pollutants during the smoggiest period of the year in Southern California and reducing the costs/losses from wildfires.
- Agriculture is also located in the areas of the state that fail to meet air quality standards, and is experiencing the greatest pressures for disposal alternatives.
- Because of the growing biomass waste disposal problems, there are likely to be additional state subsidies to divert materials into commercial use.
- Significant volumes of agriculture and forest biomass are burned, contributing to air quality and other environmental problems.
- Biomass waste disposal alternatives are decreasing and costs are increasing.
- Of the 43 million BDT of biomass generated in California annually, up to 9 million tons have been used in the biomass power plant industry. However, the biomass power plant industry is shutting down a significant number of their plants, reducing biomass usage to less than 6 million tons annually, thereby creating a surplus of biomass in the waste stream and driving the biomass fuel prices down from a peak of \$40/BDT to \$15-18/BDT during the last 18 months. The power plant users of biomass have an objective to receive delivered feedstock at close to \$0/BDT.
- Three factors are increasing the volumes of biomass materials in the state's waste stream: population increases, increasing regulatory limitations and costs for disposing of biomass through burning or landfilling, and a significant volume of forest residue that needs to be disposed of to reduce wildfire threats on California's public and private timber, brush, and hardwood covered wildlands.

AREAS OF BIOMASS CONCENTRATIONS IN CALIFORNIA

Rice Straw Generation in the Sacramento Valley

A review of the crop data within the County Agricultural Commissioners Crop Reports indicates that within the Sacramento Valley, approximately 490,000 acres of rice are currently grown annually.

Table 80 shows the acreage planted and estimated rice straw by county. This acreage is 96% of the total rice grown in California. It is estimated that approximately 3 BDT of straw are generated per acre for a total of nearly 1.5 million BDT of rice straw on an annual basis. The Sacramento Valley region is clearly a prime candidate for an ethanol plant site.

The rice-growing soils in Sacramento Valley are mostly heavy clay with high water tables, and can not viably grow any crop except rice. Of the approximately 500,000 acres of rice growing lands in the Sacramento Valley, it is estimated that 300,000 acres are the heavier clay soils that cannot be used for alternative crops. The remaining lands are silty clay and silty clay loams that can grow alternative crops. Because of the high water table and access to extensive supplies of surface water, growers in the rice area have very secure water supplies for irrigation. Unlike many other areas in California, the availability of well water as a backup for the rice growing area has meant that water availability is less limiting to rice than to most other California agricultural crops. Hence, the planted acreage has not dropped below the range of 325,000 to 500,000 acres (Table 81).

Table 80: Rice Acreage and Rice Straw Generation for the Sacramento Valley

<i>County</i>	<i>Rice Acreage*</i> (acres/yr)	<i>Rice Straw</i> (BDT/yr)
Butte	98,200	294,600
Colusa	128,690	386,070
Glenn	83,686	251,058
Placer	16,800	50,400
Sacramento	8,650	25,950
Sutter	93,164	279,492
Tehama	1,500	4,500
Yolo	25,999	77,997
Yuba	35,880	107,640
Total	492,569	1,477,707

*Rice acreage based on County Agricultural Commissioner Crop Reports for 1996.

Table 81: California Rice Acreage Harvested, 1986–1997

<i>Year</i>	<i>Acres</i>
1986	360,000
1987	370,000
1988	425,000
1989	410,000
1990	395,000
1991	350,000
1992	394,000
1993	437,000
1994	485,000
1995	465,000
1996	518,000
1997	513,000

The 1998 harvested acres is estimated to be approximately 470,000 acres. This lower acreage can be attributed primarily to the impact of the late spring rains caused by El Niño.

A review of the data prepared by the California Department of Food and Agriculture, Statistics Service indicates that during the period of 1990 through 1995, rice production averaged approximately 3.25 BDT per acre, ranging from a low of 3.04 BDT per acre to a high of 3.4 BDT per acre.

The following map (Figure 84) identifies the concentrations of rice straw in Northern California and reflects the potential areas that could be considered for locating biomass-to-ethanol facilities. Currently there are two proposed biomass-to-ethanol facilities that will use rice straw: one in the northern part of Sacramento County, and the other in Butte County.

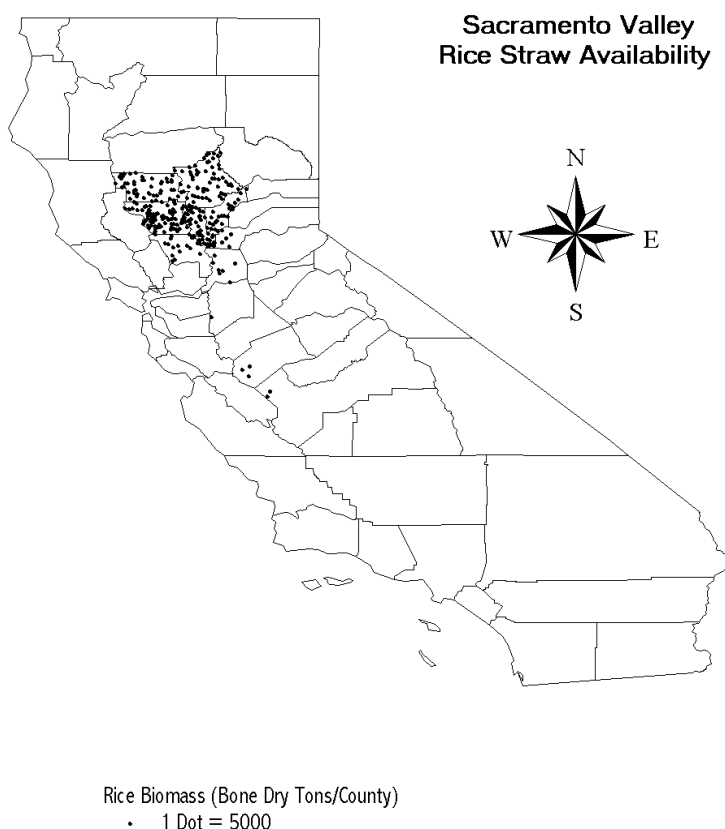


Figure 84: Sacramento Valley Rice Straw Availability

Forest Residue Generation for Northeastern California

Within California, over 2 billion board feet of timber are harvested annually. In the course of this harvest, wood residue is generated and much of it is disposed of by open burning. It is estimated that within California approximately 4.5 million BDT of biomass residue is generated during timber harvest and an additional 50%, (approximately 2 million BDT) more residue is available from thinnings and fuel reduction treatments.

Northeastern California is a region of concentrated forests, and hence, is identified as a good candidate for the development of an ethanol plant site. It is estimated that within the Northeastern California region a total of approximately 3 million BDT of forest residue are generated annually. Table 82 reflects the timber harvest, associated logging residue, and an estimate of the forest residue available from thinnings and fuel reduction for the counties in Northeastern California.

Table 82: Forest Residues in Northeastern California

<i>County</i>	<i>Timber Harvest (MBF)</i>	<i>Harvest Residue (BDT)</i>	<i>Thinning/Fuel Reduction Residue (BDT)</i>	<i>Total (BDT)</i>
Butte	86,867	171,128	85,564	256,692
El Dorado	73,140	144,086	72,043	216,129
Lassen	65,278	128,598	64,299	192,897
Modoc	30,342	59,774	29,887	89,661
Nevada	61,832	121,809	60,905	182,714
Placer	49,265	97,052	48,526	145,578
Plumas	105,651	208,132	104,066	312,198
Shasta	187,977	370,315	185,157	555,472
Sierra	58,327	114,904	57,452	172,356
Siskiyou	178,701	352,041	176,021	528,062
Tehama	103,753	204,393	102,196	306,589
Yuba	33,136	65,278	32,639	97,917
Total	1,034,269	2,037,510	1,018,755	3,056,265

Figure 85 identifies the concentrations of forest residues in California and reflects the potential areas that could be considered for locating biomass-to-ethanol facilities. Currently there are two proposed biomass-to-ethanol facilities that will use forest residue: one in the Plumas County, and the other in Butte County.

Factors Influencing Biomass Feedstock Availability

Although there are presently considerable quantities of forest residue available in Northeastern California to be used as biomass feedstock, it is important to understand factors that will influence the amount of biomass feedstock available, such as:

Weather - The weather will influence the seasonal availability of forest residue as feedstock. This area can have winter rain and snows. The weather will not influence the quantity available but will affect the timing of collection. Winter rain and snow will limit forest operations and may increase delivered costs.

Wood Products Industry - The wood products industry will influence the amount of biomass available from timber harvesting operations. This industry has a cyclical history and during depressed times, mills may either reduce production or close.

Governmental Action - Certain governmental action could influence the amount of commercial timber available for harvesting; funding for public forest management and thinning, and changes in logging practices; all of which could influence the volume and cost of wood waste available from forest sources.

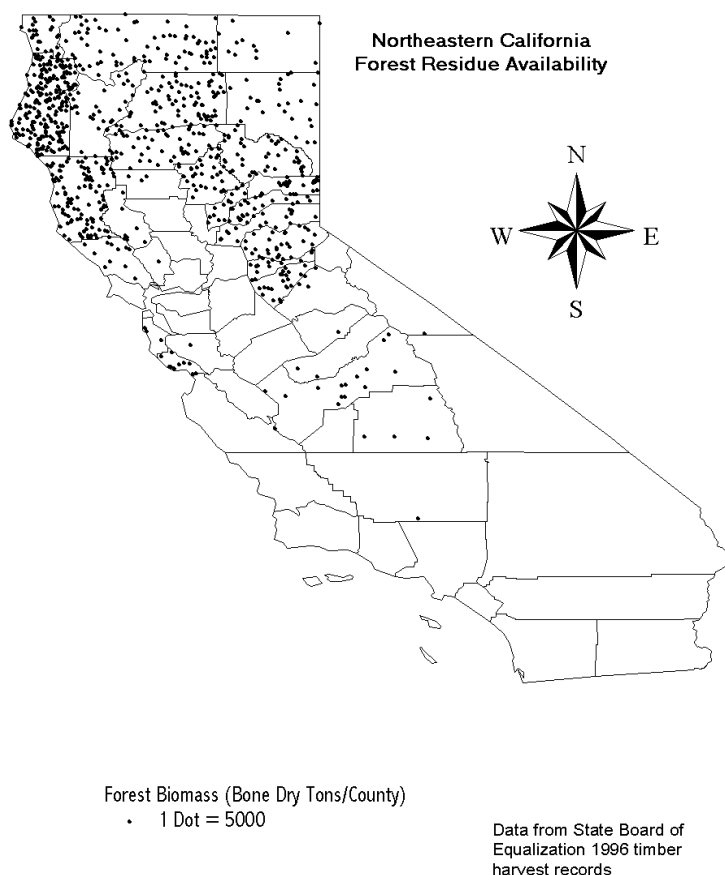


Figure 85: Forest Residue Biomass Potential

Chaparral Residue Generation in Southern California

Within California, there are between 9 million and 20 million acres of chaparral lands with an estimated 56 million to 459 million tons of standing biomass. During the past 10 years, an average of 102,926 acres has burned annually in wildfires. It is estimated that approximately 2 million tons of chaparral have burned each year.

Southern California is a region of concentrated chaparral residue that has experienced encroachment of urban development. The removal of these wildland fuels around homes and other high value environmental and economic assets as well as creating fuel breaks along ridges to use in wildfire suppression efforts can generate a portion of the feedstock requirement for the development of a biomass-to-ethanol plant.

The following map (Figure 86) identifies the concentrations of chaparral residues in Southern California and reflects the potential areas that could be considered for locating a biomass-to-ethanol facility.

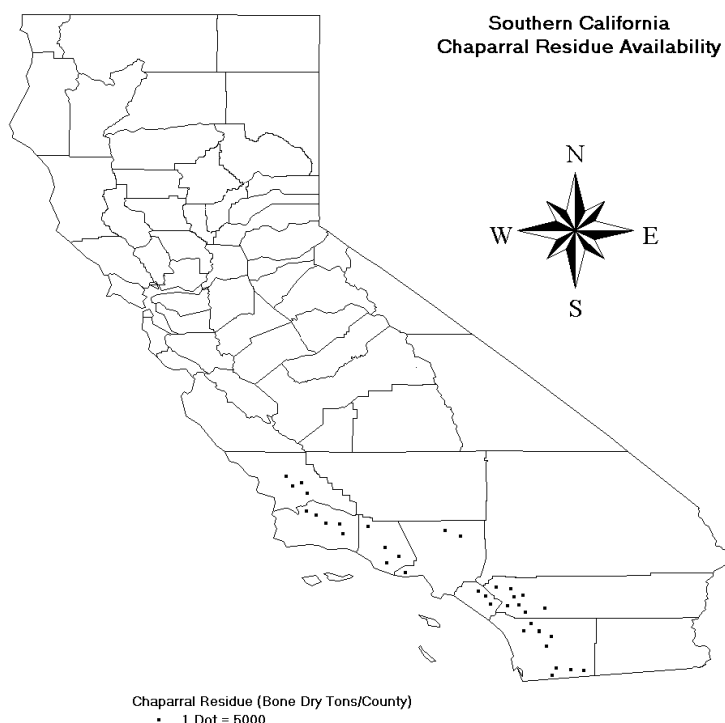


Figure 86: Southern California Chaparral Residue Availability

PROJECTED BIOMASS COLLECTION, HARVESTING, PROCESSING AND TRANSPORTATION COSTS

Economics of Forest Residue as a Raw Material

This section provides estimated costs of delivering forest residue from thinning operations on timberlands located within Northeastern California. The total cost of forest residue will vary depending upon the amount of subsidy that can be achieved from timberland owners from the private industrial sector and from the U.S. Forest Service on national forest lands. These subsidies can be in the form of payments per acre for accomplishing forest residue removal and for thinning as well as the value of sawlogs offered with the biomass material.

The cost of collection, harvesting, processing, and transportation can vary greatly from job to job depending upon factors such as tree size and density, slope of the ground, size of the project, and distance to the ethanol facility. The estimate shown in Table 83 was developed assuming fairly average site conditions and a subsidy of \$375 per acre from the U.S. Forest Service for accomplishing this thinning. Based upon these assumptions, the estimated cost of forest residue from this thinning sale would be \$22.16/BDT.

Table 83: Estimated Cost of XYZ Thinning Sale Delivered to Ethanol Facility

<i>Cost Item</i>	<i>Estimated Cost (\$/BDT)</i>
Shearing	\$12.00
Skidding	\$8.00
Chipping	\$10.00
Other Site Work	\$3.05
Road Maintenance & Surface Rep.	\$3.06
Stumpage	\$2.26
Move In*	\$0.25
Trucking @ \$200/load and 14.3 BDT/load	\$13.99
Total Operator Cost	\$52.61
Forest Service Payment	\$30.45
Total Cost to Facility	\$22.16

* Move in costs are spread over the entire contract of an estimated 10,000 BDT.

Economics of Rice Straw as a Raw Material

The total cost of baling rice straw and loading it aboard trucks is estimated at \$19.53/BDT. Including transportation costs yields an estimated cost of \$26.05/BDT for delivering rice straw delivered directly to a user facility (Table 84). For the portion of straw that must be delivered to an off-site storage location for later delivery to the facility, there is an estimated additional cost of \$11.87/BDT. The grower's alternative cost of soil incorporation can be used as a base-line cost to the farmer, and an average cost of \$10–15/BDT can be deducted to derive a net cost of straw for off-field use. Using a more conservative \$10/BDT credit, a net cost of \$16.05/BDT is calculated. The actual cost to a project will depend on the plant size and the credit to be negotiated with various farmers.

Table 84: Cost Estimates for Delivering Rice Straw to a User Facility

Direct Delivery to Facility from Grower

<i>Operation</i>	<i>Estimated Cost (\$/BDT)</i>
Swathing, raking, baling, roadsiding, and loading from field	19.53
Hauling to facility	6.52
Total FOB facility	26.05
Less Grower Credit	10.00
Total FOB facility, net basis	16.05

Delivery from Grower to Interim Storage, to Facility

<i>Operation</i>	<i>Estimated Cost (\$/BDT)</i>
Swathing, raking, baling, roadsiding, and loading from field	19.53
Hauling to facility	6.52
Unloading, storage, loading, transportation	11.87
Total FOB facility	37.92
Less Grower Credit	10.00
Total FOB facility, net basis	27.92

Assuming that 50% of the rice straw will be delivered directly to the ethanol facility and will not require interim storage, it is estimated that the average delivered cost of rice straw delivered to an ethanol facility will be \$22/BDT.

Economics of Chaparral as a Raw Material

This section provides estimated costs of delivering chaparral residue from fuel reduction treatments on wildlands located within southern California. Some removal of this material is occurring with the use of inmate crews and other publicly funded conservation crews to construct and maintain fuel breaks by hand clearing, piling, and open burning chaparral to protect high-value assets such as homes, reservoirs, and environmentally sensitive areas. Where this is being done, the majority of the cost is already being covered and the cost of feedstock delivered to a facility would be equivalent to the cost of transportation or approximately \$10–15/BDT.

For the volume of chaparral residue that would be collected above the amount already being collected, the cost would need to be subsidized by those receiving the benefits. Based upon the biomass harvesting evaluation that was conducted by the CDF, Riverside Ranger Unit, in the spring of 1998, the total costs of collection, processing and loading of chaparral residue aboard a truck is estimated to be approximately \$95/BDT. The total cost of chaparral residue delivered to a facility will be directly related to the amount of subsidy that can be derived from homeowners adjacent to these wildlands as well as from state and federal agencies desiring to protect other high-value environmental and economic assets.

APPENDIX D: GASOLINE MODELING

The flow chart shown in Figure 87 outlines the life cycle modeling of petroleum-based products used in this LCI study.

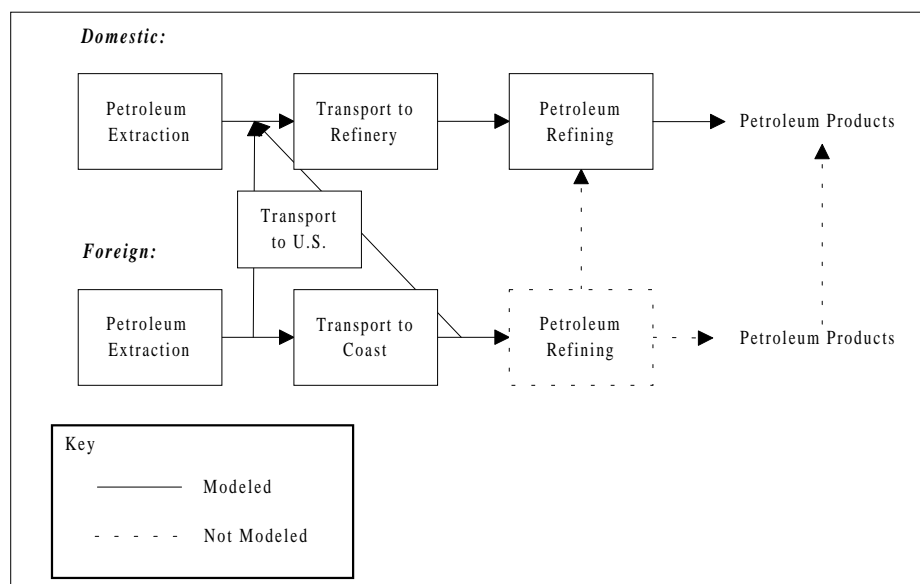


Figure 87: Petroleum Products Modeling

This Appendix describes each phase of the life cycle in more detail as shown in the following sub-sections:

- **Crude Oil Extraction:** This section describes the process flows associated with crude oil extraction from the ground and explains model assumptions.
- **Crude Oil Transport to Refinery:** This section explains how transportation is regionalized by the five different PADDs. It also explains how transportation distances were calculated and describes the different transportation models that are utilized to depict the transport of crude oil.
- **Crude Oil Refining:** This details the modeling of refinery process flows, including raw materials and energy use as well as emissions.
- **Transportation to Distribution Facility:** This section defines how transportation to a distribution facility is calculated or estimated.

CRUDE OIL EXTRACTION

Three separate methods for crude oil extraction or recovery are modeled in the overall petroleum extraction system, all based on a recent life cycle study of U.S. petroleum production processes [1]. The three methods involved are onshore production, offshore production, and enhanced recovery, the latter entailing the underground injection of steam (produced by natural gas boilers) or CO₂ to enhance the extraction of crude oil. Percentages of total crude oil extraction by each process for domestic and foreign production are given in Table 85.³⁴

³⁴ Shares of each production type were obtained from the Oil & Gas Journal Database, using numbers obtained in 1994. Note that the Enhanced/Advanced category includes all advanced crude oil extraction techniques except water flooding. It is assumed that steam flooding and CO₂ injection will represent the largest portion of the Enhanced/Advanced techniques obtained from the Oil & Gas Journal Database.

Table 85: Production of Crude Oil by Technology Type and Origin

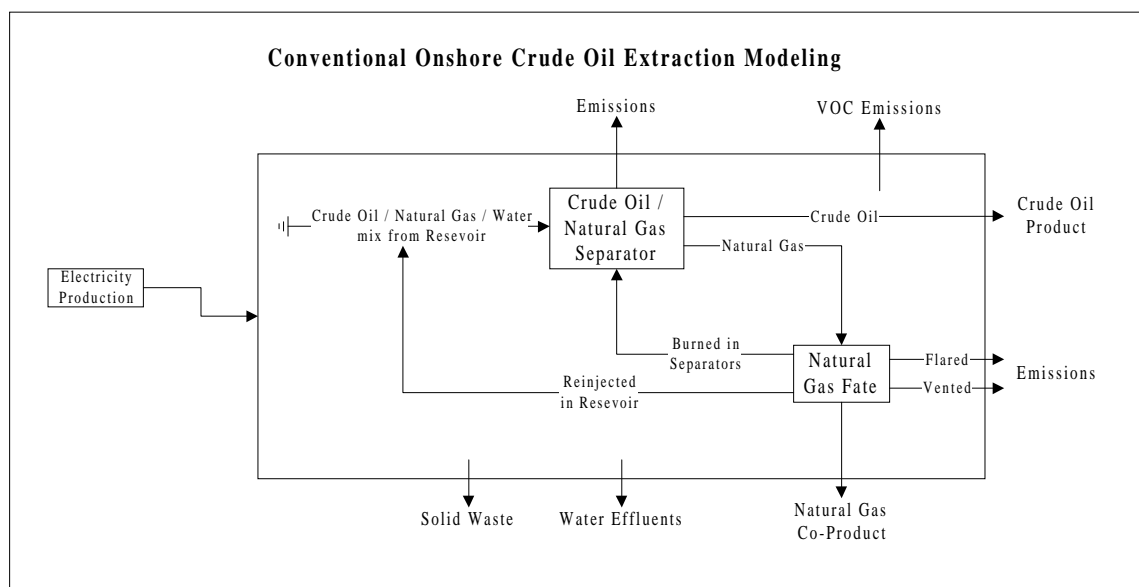
<i>Technology Type</i>	<i>Domestic Crude Oil Production</i>	<i>Foreign Crude Oil Production</i>
Conventional Onshore	69%	77%
Conventional Offshore	20%	20%
Enhanced/Advanced	11%	3%

Of the total Enhanced/Advanced crude oil extraction techniques, steam injection is assumed to account for 63% of the total and CO₂ injection is assumed to account for the remaining 37%.

Each of these production types will be considered in more detail in the following sections.

Conventional Onshore Extraction

Figure 88 shows the system process diagram associated with conventional onshore crude oil extraction. It demonstrates the system boundaries and process flows considered for modeling conventional onshore crude oil extraction in this study.

**Figure 88: Conventional Onshore Crude Oil Extraction**

Material Use

As is seen in Figure 88, the only material inputs required for conventional onshore crude oil extraction is the actual crude oil and natural gas in the ground. It is assumed that there is no loss of crude oil once it is extracted from the well. Therefore, to produce one kg of crude oil would require one kg of crude oil from the ground.

The life cycle environmental flows associated with the production of the capital equipment and facilities used in the extraction of crude oil are excluded from this study. However, the energy required for drilling and exploration are included in the study. For conventional onshore crude oil production, exploration and drilling energy represent approximately 0.75% of the energy in the produced crude oil [2]. This energy is primarily used for drilling. This energy is accounted for by decreasing the yield for crude oil extraction or by increasing the amount of crude oil in the ground needed to produce one kg of crude oil. Therefore, conventional onshore crude oil extraction would require 1.0075 kg of crude oil in the ground to produce one kg of crude oil. The material requirements for both domestic and foreign conventional onshore crude oil extraction are assumed to be the same.

Energy/Equipment Use

Energy used in the actual extraction of crude oil is accounted for in this study. It primarily comes from the gross production of the well and from purchased electricity. Energy requirements for both domestic and foreign conventional onshore crude oil production are based on a 400-well production field (195 unproductive wells) located in the lower 48 states producing 4.98×10^9 kg/yr (3.65×10^7 bbl/yr) of crude oil as follows [3]:

Electricity:	10.7 kilowatt-hr/bbl	(used in pumping)
Natural Gas:	5.2 MJ/bbl	(used in recovery)

Electricity is assumed to come from a standard U.S. grid while natural gas is assumed to come from gross production of the well. The LCI information on the production of electricity is included in the overall LCI of crude oil extraction and is taken from Ecobalance's database DEAMTM.

Modeling of foreign crude oil extraction electricity use based on the standard U.S. grid is not necessarily an accurate representation of the actual electricity production used at foreign oil fields. However, foreign crude oil used in the U.S. is coming from all over the world and modeling of the exact electricity use at foreign fields would require studying each site individually³⁵. Therefore, the U.S. standard grid was used as a surrogate for foreign electricity production. This is an estimate because foreign electricity production sources may not meet the same strict emission guidelines as in the United States.

Process Emissions

The process emissions from conventional onshore crude oil extraction include air, water, and solid waste emissions.

Water effluents are based on the amount of wastewater produced and the average composition of the wastewater. The amount of wastewater disposed of by conventional onshore crude oil production is found to be 0.7 liters/kg of crude oil produced [4]. The actual wastewater produced is more than this but only 0.7 liters are actually released to the environment. The rest is treated on site through re-injection, evaporation, etc.

The constituents and concentrations of the wastewater are shown in the following table (Table 86).

Table 86: Crude Oil Production Wastewater Constituents and Concentrations

<i>Constituent</i>	<i>Median Concentration (mg/l)</i>
Arsenic	0.02
Benzene	0.47

Water effluents of oil and grease are estimated to be 1×10^{-4} kg/kg crude oil produced [3].

The emission factor for the production of solid waste is calculated as 0.0098 grams of solid waste for every kg of crude oil [1].

Air emissions from conventional onshore crude oil extraction come from the combustion of natural gas in the crude oil/natural gas separators, venting and flaring of natural gas as well as from volatilization (fugitive) emissions of crude oil.

The emission factors for natural gas combustion of the crude oil/natural gas separators were assumed to be the same as industrial boilers. This was an estimate since many of these burners are located in remote sites where requirements for emissions may be less stringent.

The natural gas venting/flaring emissions from crude oil extraction have been calculated based on a percentage of the gross natural gas production of the well. The following table (Table 87) outlines the natural gas venting/flaring calculations from conventional onshore crude oil extraction:

³⁵ Actually, each U.S. crude oil production field would have its own mix of electricity use. However, the standard U.S. grid was used to represent an average situation.

Table 87: Natural Gas Venting and Flaring from Crude Oil Wells

	<i>Conventional Onshore Extraction</i>
Gross NG extracted (kg/kg crude)	0.47
Domestic % Flared	1.22 %
Domestic % Vented	0.03 %
Foreign % Flared	4.53 %
Foreign % Vented	0.12 %

These numbers are based on the following sources:

Gross natural gas extracted - EIA Natural Gas Annual 1994, gives gross extraction of natural gas from crude oil wells. Crude oil production from EIA Petroleum Supply Annual 1997 (1994 crude oil production used). Domestic and foreign crude oil wells are assumed to produce the same amount of natural gas in relation to the crude oil produced.

Domestic % Flared/Vented - EIA Natural Gas Annual 1994, gives the amount of natural gas vented/flared for onshore extraction. The percentage of flared/vented gas is assumed to be the same for total natural gas as for natural gas from crude oil wells.

Foreign % Flared/Vented - EIA International Energy Annual 1995, gives the amount of natural gas flared/vented (1994 numbers used). The percentage of flared/vented gas is assumed to be the same for total natural gas as for natural gas from crude oil wells and for offshore and onshore extraction.

Assumptions:

97.5% of the total flared/vented onshore natural gas was assumed to be flared (2.5 % vented) [2].

From Table 87 above, it can be seen that the amount of domestic natural gas flared during conventional onshore crude oil extraction is 1.22 % of the gross natural gas produced from the well. The amount of domestic natural gas that is vented is 0.03 % of the gross natural gas produced by the well. Based on the amount of gas produced by the well, this relates to 0.0057 and 0.00014 kg of natural gas flared and vented respectively per kg of domestic onshore crude oil extracted.

From Table 87, the amount of foreign natural gas flared during conventional onshore crude oil extraction is 4.53 % of the gross natural gas produced from the well. The amount of foreign natural gas that is vented is 0.12 % of the gross natural gas produced by the well. This relates to 0.021 and 0.00056 kg of natural gas flared and vented respectively per kg of foreign onshore crude oil extracted.

The amount that is vented was assumed to be released as methane. The emissions from the amount that is flared are based on the emission factors for industrial flares.

VOC emissions from onshore crude oil extraction are shown in Table 88 as taken from a U.S. EPA report[5].

Table 88: VOC Emissions for Onshore Crude Oil Wells

<i>Component</i>	<i>Emission Factor (g/well-yr)</i>
Fugitive Emissions	180,000
Crude Oil Sumps	4,000
Crude Oil Pits	4,000
Total	188,000

These VOC emissions are further speciated as shown in Table 89 [5].

Table 89: Speciated VOC Data for Onshore Crude Oil Wells

<i>Compound</i>	<i>Weight %</i>
Isomers of hexane	9.9
Isomers of heptane	11.6
Isomers of octane	8.7
C-7 Cycloparaffins	1.6
C-8 Cycloparaffins	0.6
Isomers of pentane	5.6
Methane	38.0
Ethane	6.4
Propane	10.0
n-Butane	7.4
iso-Butane	0.4
Benzene	0.1

In 1994 the average productivity of U.S. crude oil production wells was 1,555 kg of crude oil/day per well (11.4 bbl/day per well) [6]. Using this number, VOC emissions data can be calculated per kilograms of crude oil produced.

Crude Oil Production

Crude oil extracted from the ground by the different technologies must undergo an additional step before it is ready to be shipped to refineries. The crude oil extracted from the ground is a mixture of crude oil, natural gas, and water. Crude oil/natural gas separators operating in the field are used to separate the three components. These separators are assumed to be burning natural gas as explained in the previous sections. The combustion of this natural gas leads to air emissions. However, because natural gas is being produced as a coproduct of crude oil production, the emissions associated with the crude oil/natural gas separators, as well as other emission sources from crude oil extraction, need to be allocated between crude oil and natural gas production.

Conventional onshore crude oil extraction is assumed to produce natural gas as a coproduct. The amount of natural gas produced is shown (Table 90).

Table 90: Natural Gas Venting, Flaring, and Coproduct Production from Onshore Extraction Wells

<i>Parameter</i>	<i>Value</i>
Gross NG extracted (kg/kg crude)	0.47
Domestic % Re-injected	17.8 %
Domestic % Flared/Vented	1.25 %
Foreign % Re-injected	9.98 %
Foreign % Flared/Vented	4.65 %
Coproduct Domestic	$80.95 \% \times 0.47 = 0.38 \text{ kg}$
Coproduct Foreign	$85.37 \% \times 0.47 = 0.40 \text{ kg}$

These numbers are based on the following sources:

Gross natural gas extracted - EIA Natural Gas Annual 1994, gives gross extraction of natural gas from crude oil wells. Crude oil production from EIA Petroleum Supply Annual 1997 (1994 crude oil production used). Domestic and foreign crude oil wells are assumed to produce the same amount of natural gas in relation to the crude oil produced.

Domestic % Re-injected - EIA Natural Gas Annual 1994, gives the amount of natural gas re-injected for both offshore and onshore extraction. The percentage of re-injected gas is assumed to be the same for total natural gas as for natural gas from crude oil wells.

Domestic % Flared/Vented - EIA Natural Gas Annual 1994, gives the amount of natural gas vented/flared for both offshore and onshore extraction. The percentage of flared/vented gas is assumed to be the same for total natural gas as for natural gas from crude oil wells.

Foreign % Re-injected - EIA International Energy Annual 1995, gives the amount of natural gas re-injected (1994 numbers used). The percentage of re-injected gas is assumed to be the same for total natural gas as for natural gas from crude oil wells and for offshore and onshore extraction.

Foreign % Flared/Vented - EIA International Energy Annual 1995, gives the amount of natural gas flared/vented (1994 numbers used). The percentage of flared/vented gas is assumed to be the same for total natural gas as for natural gas from crude oil wells and for offshore and onshore extraction.

The amount of natural gas re-injected into the well and the amount of natural gas that is either vented or flared is not be considered to be a coproduct of crude oil extraction.

The following tables (Table 91 and Table 92) show the mass of crude oil and natural gas produced by the wells considered in this project:

Table 91: Production of Typical Domestic Conventional Onshore Crude Oil Well

	<i>Mass (kg)</i>	<i>Mass (%)</i>
Crude Oil:	1	72 %
Natural Gas:	0.38	28 %
Total:	1.38	

Table 92: Production of Typical Foreign Conventional Onshore Crude Oil Well

	<i>Mass (kg)</i>	<i>Mass (%)</i>
Crude Oil:	1	71 %
Natural Gas:	0.40	29 %
Total:	1.40	

Emissions from flaring, venting, crude oil/natural gas separators, and fugitive emissions as well as raw materials, and energy use are allocated between natural gas and crude oil production based on the mass percentage of crude oil produced. For example, with conventional domestic onshore crude oil production, 72% of the total emissions, raw materials, and energy use is allocated to crude oil.

Conventional Offshore Extraction

Figure 89 shows the system process diagram associated with conventional offshore crude oil extraction. It demonstrates the system boundaries and process flows considered for modeling conventional offshore crude oil extraction in this study.

Material Use

As is seen in Figure 89, the only material inputs required for conventional offshore crude oil extraction, accounted for in this study, is the actual crude oil and natural gas in the ground. It is assumed that there is no loss of crude oil once it is extracted from the well. Therefore, to produce one kg of crude oil would require one kg of crude oil from the ground.

The life cycle environmental flows associated with the production of the capital equipment and facilities used in the extraction of crude oil are excluded from this study. However, the energy required for drilling and exploration are

included in the study. For conventional offshore crude oil production, exploration and drilling energy represents approximately 7%-8% of the energy in the produced crude oil [2]. The average, or 7.5%, is used in this study, this energy is primarily used for drilling.

This energy is accounted for by decreasing the yield for crude oil extraction or by increasing the amount of crude oil in the ground needed to produce one kg of crude oil. Therefore, conventional offshore crude oil extraction would require 1.075 kg of crude oil in the ground to produce one kg of crude oil.

The material requirements for both domestic and foreign conventional offshore crude oil extraction are assumed to be the same.

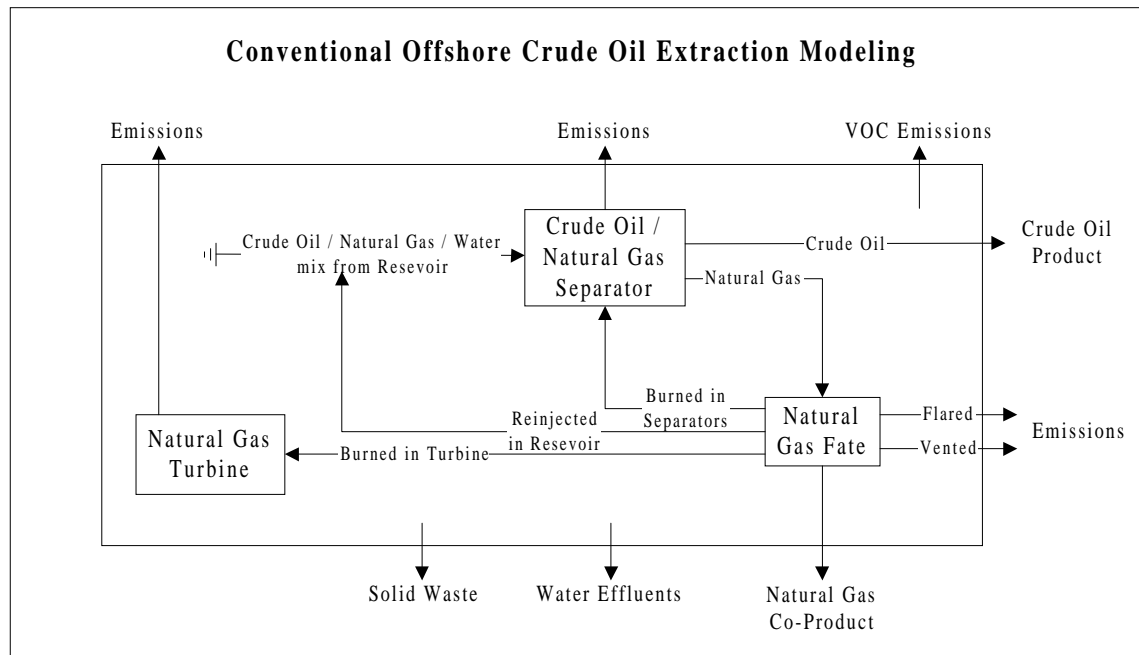


Figure 89: Conventional Offshore Crude Oil Extraction

Energy/Equipment Use

Energy used in the actual extraction of crude oil is accounted for in this study. It primarily comes from the gross production of the well. Energy requirements for both foreign and domestic conventional offshore crude oil production are based on an 18 well offshore platform producing 1.97×10^8 kg of crude oil/yr (1.46×10^6 bbl/yr) [3] as follows³⁶:

Natural Gas:	38.8 MJ/bbl	(used in recovery)
Natural Gas:	96.6 MJ/bbl	(used to produce electricity for pumping and other needs)

The natural gas used for the crude oil / natural gas separators and for electricity production is assumed to come from gross production of the well.

Process Emissions

The process emissions from conventional offshore crude oil extraction include air, water, and solid waste emissions.

³⁶ Electrical energy requirements are assumed to be met through the use of natural gas turbines.

Water effluents are based on the amount of wastewater produced and the average composition of the wastewater. The amount of wastewater disposed of by conventional offshore crude oil production is found to be 10.14 liters/kg of crude oil produced [7]. All of the wastewater produced is assumed to be released to the surrounding water.

The constituents and concentrations of the wastewater are shown in Table 93 [4].

Table 93: Crude Oil Production Wastewater Constituents and Concentrations

<i>Constituent</i>	<i>Median Concentration (mg/l)</i>
Arsenic	0.02
Benzene	0.47

Water effluents of oil and grease are estimated to be 2.8×10^{-4} kg/kg crude oil produced [7].

The emission factor for the production of solid waste is calculated as 0.0098 grams of solid waste for every kg of crude oil [1].

Air emissions from conventional offshore crude oil extraction come from the combustion of natural gas in the crude oil/natural gas separators and natural gas turbine, venting and flaring of natural gas as well as from volatilization (fugitive) emissions of crude oil.

The emission factors for natural gas combustion of the crude oil/natural gas separators were assumed to be the same as industrial boilers. This may be conservative since many of these burners are located in remote sites where requirements for emissions may be less stringent. The emission factors for natural gas combustion used to produce electricity are based on natural gas emission factors from a gas turbine.

The natural gas venting/flaring emissions from crude oil extraction have been calculated based on a percentage of the gross natural gas production of the well. The following table (Table 94) outlines the natural gas venting/flaring calculations from conventional offshore crude oil extraction:

Table 94: Natural Gas Venting and Flaring from Conventional Offshore Extraction Wells

<i>Parameter</i>	<i>Value</i>
Gross NG extracted (kg/kg crude)	0.26
Domestic % Flared	0.067 %
Domestic % Vented	0.022 %
Foreign % Flared	3.49 %
Foreign % Vented	1.16 %

These numbers are based on the following sources:

Gross natural gas extracted - EIA Natural Gas Annual 1994, gives gross extraction of natural gas from crude oil wells. Crude oil production from EIA Petroleum Supply Annual 1997 (1994 crude oil production used). Domestic and foreign crude oil wells are assumed to produce the same amount of natural gas in relation to the crude oil produced.

Domestic % Flared/Vented - EIA Natural Gas Annual 1994, gives the amount of natural gas vented/flared for offshore extraction. The percentage of flared/vented gas is assumed to be the same for total natural gas as for natural gas from crude oil wells.

Foreign % Flared/Vented - EIA International Energy Annual 1995, gives the amount of natural gas flared/vented (1994 numbers used). The percentage of flared/vented gas is assumed to be the same for total natural gas as for natural gas from crude oil wells and for offshore and onshore extraction.

Assumptions:

Seventy-five percent of the total flared/vented offshore natural gas was assumed to be flared (25 % vented) [2].

From Table 94 above, it can be seen that, the amount of domestic natural gas flared during conventional offshore crude oil extraction is 0.067% of the gross natural gas produced from the well. The amount of domestic natural gas

that is vented is 0.022% of the gross natural gas produced by the well. Based on the amount of gas produced by the well, this relates to 0.00017 and 0.000057 kg of natural gas flared and vented, respectively, per kg of domestic offshore crude oil extracted.

From Table 94 above, the amount of foreign natural gas flared during conventional offshore crude oil extraction is 3.49 % of the gross natural gas produced from the well. The amount of foreign natural gas that is vented is 1.16 % of the gross natural gas produced by the well. This relates to 0.0091 and 0.0030 kg of natural gas flared and vented, respectively, per kg of foreign offshore crude oil extracted.

The amount that is vented is assumed to be released as methane. The emissions from the amount that is flared are based on the emission factors for industrial flares.

VOC emissions for conventional offshore crude oil production are calculated based on Table 95 [1]:

Table 95: Speciated VOC Emissions for Offshore Crude Oil Production

<i>Emission</i>	<i>Rate</i> (kg/kg crude oil produced)
Methane	5.6×10^{-5}
Formaldehyde	1.9×10^{-5}
Isomers of hexane	3.0×10^{-6}
Isomers of heptane	2.3×10^{-5}
Isomers of octane	2.6×10^{-6}
C-7 Cycloparaffins	3.2×10^{-6}
C-8 Cycloparaffins	1.2×10^{-6}
Isomers of pentane	1.1×10^{-5}
Ethane	1.3×10^{-5}
Propane	2.0×10^{-5}
n-Butane	1.5×10^{-5}
iso-Butane	8.0×10^{-7}
Benzene	2.0×10^{-7}

Crude Oil Production

Crude oil extracted from the reservoir by the different technology types must undergo an additional step before it is ready to be shipped to refineries. The crude oil is extracted from the reservoir in a mixture of crude oil, natural gas, and water. Crude oil/natural gas separators operating in the field are used to separate the three components. These separators are assumed to be burning natural gas as explained in the previous sections.

The combustion of this natural gas leads to air emissions. However, because natural gas is being produced as a coproduct of crude oil production, the emissions associated with the crude oil/natural gas separators, as well as other emission sources from crude oil extraction, need to be allocated between crude oil and natural gas production.

Conventional offshore crude oil extraction is assumed to produce natural gas as a coproduct. The amount of natural gas produced is shown in Table 96.

These numbers are based on the following sources:

Gross natural gas extracted - EIA Natural Gas Annual 1994, gives gross extraction of natural gas from crude oil wells. Crude oil production from EIA Petroleum Supply Annual 1997 (1994 crude oil production used). Domestic and foreign crude oil wells are assumed to produce the same amount of natural gas in relation to the crude oil produced.

Domestic % Re-injected - EIA Natural Gas Annual 1994, gives the amount of natural gas re-injected for both offshore and onshore extraction. The percentage of re-injected gas is assumed to be the same for total natural gas as for natural gas from crude oil wells.

Domestic % Flared/Vented - EIA Natural Gas Annual 1994, gives the amount of natural gas vented/flared for both offshore and onshore extraction. The percentage of flared/vented gas is assumed to be the same for total natural gas as for natural gas from crude oil wells.

Foreign % Re-injected - EIA International Energy Annual 1995, gives the amount of natural gas re-injected (1994 numbers used). The percentage of re-injected gas is assumed to be the same for total natural gas as for natural gas from crude oil wells and for offshore and onshore extraction.

Foreign % Flared/Vented - EIA International Energy Annual 1995, gives the amount of natural gas flared/vented (1994 numbers used). The percentage of flared/vented gas is assumed to be the same for total natural gas as for natural gas from crude oil wells and for offshore and onshore extraction.

The amount of natural gas that is re-injected into the well and the amount of natural gas that is either vented or flared is not be considered to be a coproduct of crude oil extraction.

Table 96: Natural Gas Venting, Flaring, and Coproduct Production from Offshore Extraction Wells

<i>Parameter</i>	<i>Value</i>
Gross NG extracted (kg/kg crude)	0.26
Domestic % Re-injected	2.46 %
Domestic % Flared/Vented	0.09 %
Foreign % Re-injected	9.98 %
Foreign % Flared/Vented	4.65 %
Coproduct Domestic	$97.45 \% \times 0.26 = 0.25 \text{ kg}$
Coproduct Foreign	$85.37 \% \times 0.26 = 0.22 \text{ kg}$

The following tables (Table 97 and Table 98) show the mass of crude oil and natural gas produced by the wells considered in this project:

Table 97: Production of Typical Domestic Conventional Offshore Crude Oil Well

	<i>Mass (kg)</i>	<i>Mass (%)</i>
Crude Oil:	1	80
Natural Gas:	0.25	20
Total:	1.25	

Table 98: Production of Typical Foreign Conventional Offshore Crude Oil Well

	<i>Mass (kg)</i>	<i>Mass (%)</i>
Crude Oil:	1	82
Natural Gas:	0.22	18
Total:	1.22	

Emissions from flaring, venting, crude oil/natural gas separators, and fugitive emissions as well as raw materials, and energy use are allocated between natural gas and crude oil production based on the mass percentage of crude oil produced. For example, with conventional domestic offshore crude oil production, 80% of the total emissions, raw materials, and energy use is allocated to crude oil.

Advanced Onshore Extraction (Steam Injection)

Figure 90 shows the system process diagram associated with advanced onshore crude oil extraction through the use of steam injection. It demonstrates the system boundaries and process flows considered for modeling advanced steam injection onshore crude oil extraction in this study.

Material Use

As is seen in Figure 90, the only material inputs required for advanced steam injection onshore crude oil extraction, accounted for in this study, is the actual crude oil and natural gas in the ground. It is assumed that there is no loss of crude oil once it is extracted from the well. Therefore, to produce one kg of crude oil would require one kg of crude oil from the ground.

The life cycle environmental flows associated with the production of the capital equipment and facilities used in the extraction of crude oil are excluded from this study. However, the energy required for drilling and exploration are included in the study. For advanced steam injection onshore crude oil production exploration and drilling energy represents approximately 0.75% of the energy in the produced crude oil [2]. This energy is primarily used for drilling.

This energy is accounted for by decreasing the yield for crude oil extraction or by increasing the amount of crude oil in the ground needed to produce one kg of crude oil. Therefore, advanced steam injection onshore crude oil extraction would require 1.0075 kg of crude oil in the ground to produce one kg of crude oil.

The material requirements for both domestic and foreign advanced steam injection onshore crude oil extraction are assumed to be the same.

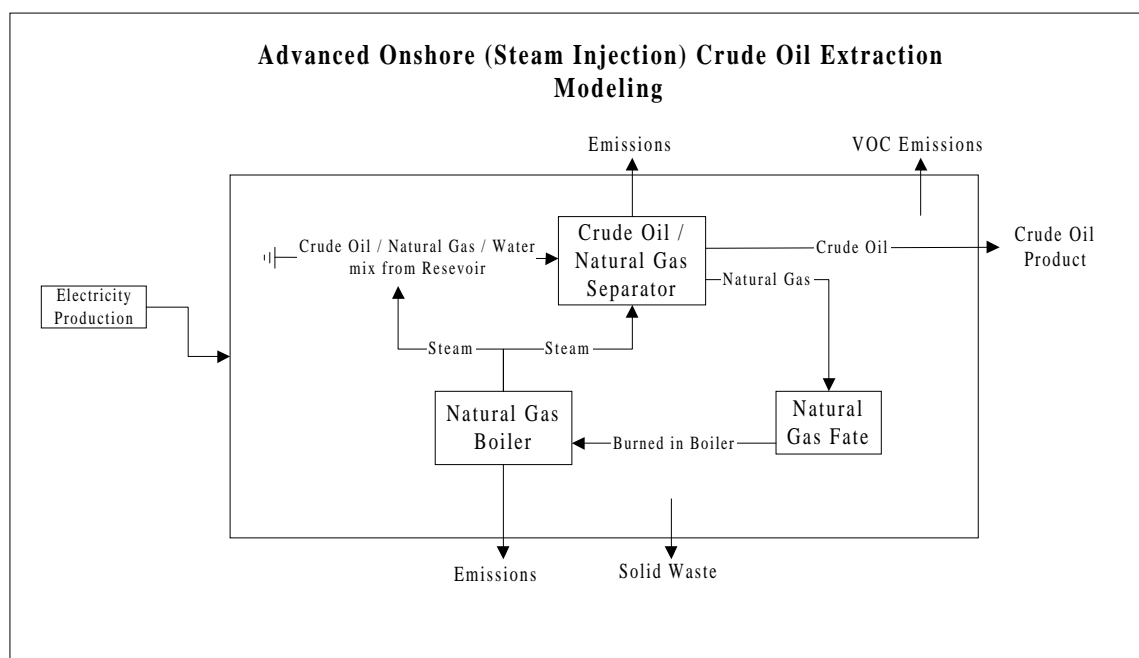


Figure 90: Advanced Onshore (Steam Injection) Crude Oil Extraction

Energy/Equipment Use

Energy used in the actual extraction of crude oil is accounted for in this study. It primarily comes from the gross production of the well and from purchased electricity. Energy requirements for both domestic and foreign advanced steam injection onshore crude oil production are based on a steam injection site located in the lower 48 states producing 4.7×10^9 kg/yr (3.45×10^7 bbl/yr) of crude oil as follows [3]:

Electricity:	11.3 kilowatt-hr/bbl	(used in pumping)
Natural Gas:	986 MJ/bbl	(used in recovery and steam boiler)

This site is assumed to require the same amount of electricity as the conventional onshore crude oil extraction site modeled previously. However, since the amount of oil produced in the steam injection site is less than that of the conventional site, more electricity is required per bbl of oil.

The steam used is assumed to be produced by natural gas fired boilers. The amount of steam used per year is estimated based on the amount of water used by the site (1.06×10^{10} liters/yr). The energy necessary to convert this water to steam is based on the enthalpy of the steam (2.6 MJ/kg @ approximately 150 psi and 350°F) and a boiler efficiency of 80%. The natural gas used in the crude oil/natural gas separators is assumed to be included in this value.

Electricity is assumed to come from a standard U.S. grid while natural gas is assumed to come from gross production of the well. The LCI information on the production of electricity is included in the overall LCI of crude oil extraction and is taken from Ecobalance's database DEAMTM.

Modeling of foreign crude oil extraction electricity use based on the standard U.S. grid is not necessarily an accurate representation of the actual electricity production used at foreign oil fields. However, foreign crude oil used in the United States is coming from all over the world and modeling of the exact electricity use at foreign fields would require studying each site individually. Therefore, the U.S. standard grid was used as a surrogate for foreign electricity production. This is a conservative estimate because foreign electricity production sources may not meet the same strict emission guidelines as in the United States.

Process Emissions

The process emissions from advanced steam injection onshore crude oil extraction include air emissions and solid waste emissions.

No wastewater is assumed to be produced by advanced steam injection onshore crude oil extraction because it is all reused in steam production. Advanced steam injection onshore extraction is actually a net user of water. However, advanced steam injection onshore crude oil extraction is assumed to produce oil and grease, estimated to be 1×10^{-4} kg/kg crude oil produced [3] although no wastewater is produced.

The emission factor for the production of solid waste is calculated as 0.0098 grams of solid waste are produced for every kg of crude oil [1].

Air emissions from advanced steam injection onshore crude oil extraction come from the combustion of natural gas in a boiler as well as from volatilization (fugitive) emissions of crude oil.

VOC emissions from onshore crude oil extraction are shown in Table 99 as taken from a U.S. EPA report [5]. These VOC emissions are further speciated as illustrated in Table 100.

Table 99: VOC Emissions for Onshore Crude Oil Wells with CO₂ Extraction

<i>Component</i>	<i>Emission Factor</i> (g/well-yr)
Fugitive Emissions	180,000
Crude Oil Sumps	4,000
Crude Oil Pits	4,000
Total	188,000

In 1994 the average productivity of U.S. crude oil production wells was 1,555 kg of crude oil/day per well (11.4 bbl/day per well). Using this number, VOC emissions data can be calculated per kilograms of crude oil produced.

Crude Oil Production

Advanced onshore crude oil extraction is assumed to burn all of the natural gas produced by the well in order to generate the steam needed for injection. Therefore, no natural gas is produced as a coproduct of advanced steam injection onshore crude oil extraction.

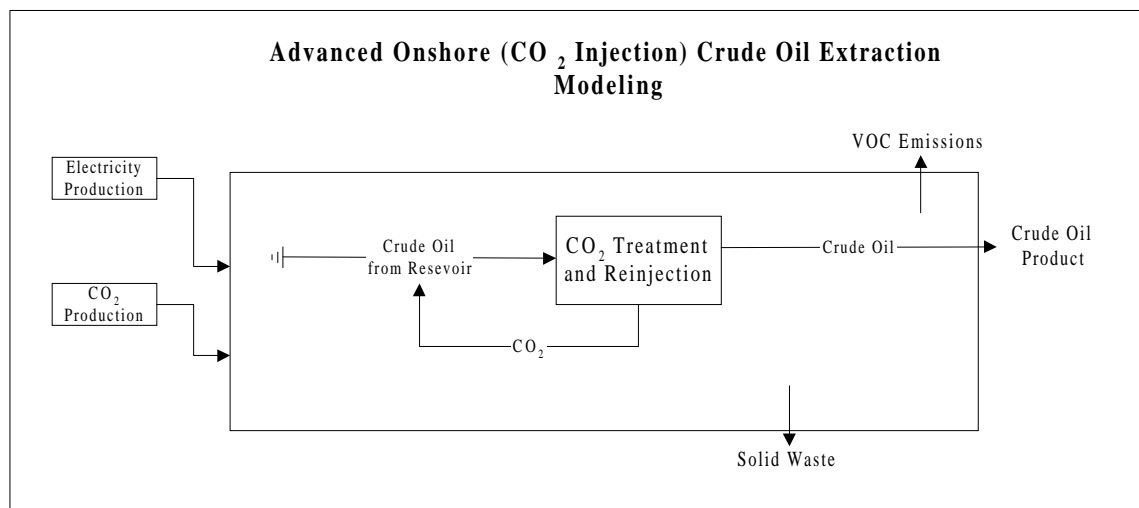
Emissions from natural gas boilers and fugitive emissions, as well as raw materials and energy use, are allocated completely to crude oil production for advanced steam injection onshore crude oil extraction.

Table 100: Speciated VOC Data for Onshore Crude Oil Wells

<i>Compound</i>	<i>Weight %</i>
Isomers of hexane	9.9
Isomers of heptane	11.6
Isomers of octane	8.7
C-7 Cycloparaffins	1.6
C-8 Cycloparaffins	0.6
Isomers of pentane	5.6
Methane	38.0
Ethane	6.4
Propane	10.0
n-Butane	7.4
iso-Butane	0.4
Benzene	0.1

Advanced Onshore Extraction (CO₂ Injection)

Figure 91 shows the system process diagram associated with advanced onshore crude oil extraction through the use of CO₂ injection. It demonstrates the system boundaries and process flows considered for modeling advanced CO₂ injection onshore crude oil extraction in this study.

**Figure 91: Advanced Onshore (CO₂ Injection) Crude Oil Extraction**

Material Use

As is seen in Figure 91, the material inputs required for advanced CO₂ injection onshore crude oil extraction, accounted for in this study, is the actual crude oil in the ground and the CO₂ required for injection. A carbon dioxide gas injection well is assumed to require 4.6 kg of CO₂ to be injected for every 1 kg of crude oil produced (15,000 scf of CO₂ per barrel of crude oil). Of this CO₂ injected, half is assumed to be sequestered in the reserve.³⁷

³⁷ This sequestered CO₂ is accounted for as a negative flow in the model.

Therefore, only 2.3 kg of carbon dioxide gas will have to be produced for every kg of crude oil extracted. The production of the carbon dioxide gas is taken from Ecobalance's database DEAMTM, based on separation from synthesis gas.

It is assumed that there is no loss of crude oil once it is extracted from the well. Therefore, to produce one kg of crude oil would require one kg of crude oil from the ground.

The life cycle environmental flows associated with the production of the capital equipment and facilities used in the extraction of crude oil are excluded from this study. However, the energy required for drilling and exploration are included in the study. For advanced CO₂ injection onshore crude oil production exploration and drilling energy represents approximately 0.75% of the energy in the produced crude oil. This energy is primarily used for drilling.

This energy is accounted for by decreasing the yield for crude oil extraction or by increasing the amount of crude oil in the ground needed to produce one kg of crude oil. Therefore, advanced CO₂ injection onshore crude oil extraction would require 1.0075 kg of crude oil in the ground to produce one kg of crude oil.

The material requirements for both domestic and foreign advanced CO₂ injection onshore crude oil extraction are assumed to be the same.

Energy/Equipment Use

Energy used in the actual extraction of crude oil is accounted for in this study. Enhanced/advanced crude oil extraction by CO₂ injection is assumed to require the same amount of electricity as the steam injection enhanced/advanced crude oil extraction site shown previously. It is also assumed that this electricity is used for the separation, drying, compression, and injection of the carbon dioxide gas.

Electricity: 11.3 kilowatt-hr/bbl (used in pumping)

Electricity is assumed to come from a standard U.S. grid. The LCI information on the production of electricity is included in the overall LCI of crude oil extraction and is taken from Ecobalance's database DEAMTM as described.

Modeling of foreign crude oil extraction electricity use based on the standard U.S. grid is not necessarily an accurate representation of the actual electricity production used at foreign oil fields. However, foreign crude oil used in the U.S. is coming from all over the world and modeling of the exact electricity use at foreign fields would require studying each site individually. Therefore, the U.S. standard grid was used as a surrogate for foreign electricity production. This is a conservative estimate because foreign electricity production sources may not meet the same strict emission guidelines as in the United States.

Process Emissions

The process emissions from advanced CO₂ injection onshore crude oil extraction include air emissions and solid waste emissions.

No wastewater is assumed to be produced by advanced CO₂ injection onshore crude oil extraction. However, advanced CO₂ injection onshore crude oil extraction is assumed to produce oil and grease, estimated to be 1×10^{-4} kg/kg crude oil produced although no wastewater is produced [3].

The emission factor for the production of solid waste is calculated as 0.0098 grams of solid waste are produced for every kg of crude oil [1].

Air emissions from advanced CO₂ injection onshore crude oil extraction come from volatilization (fugitive) emissions of crude oil.

VOC emissions from onshore crude oil extraction are shown in Table 101 as taken from a U.S. EPA report [5]. These VOC emissions are further speciated as shown in Table 102.

In 1994 the average productivity of U.S. crude oil production wells was 1,555 kg of crude oil/day per well (11.4 bbl/day per well). Using this number, VOC emissions data can be calculated per kilograms of crude oil produced.

In addition, the use of CO₂ injection to enhance the production of crude oil is assumed to result in some sequestration of the injected CO₂. It is assumed that half of the injected CO₂ is sequestered and, therefore, is accounted for as a negative flow in the life cycle.

Table 101: VOC Emissions for Onshore Crude Oil Wells

<i>Component</i>	<i>Emission Factor (g/well-yr)</i>
Fugitive Emissions	180,000
Crude Oil Sumps	4,000
Crude Oil Pits	4,000
Total	188,000

Table 102: Speciated VOC Data for Onshore Crude Oil Wells

<i>Compound</i>	<i>Weight %</i>
Isomers of hexane	9.9
Isomers of heptane	11.6
Isomers of octane	8.7
C-7 Cycloparaffins	1.6
C-8 Cycloparaffins	0.6
Isomers of pentane	5.6
Methane	38.0
Ethane	6.4
Propane	10.0
n-Butane	7.4
iso-Butane	0.4
Benzene	0.1

Crude Oil Production

It is assumed that advanced CO₂ injection onshore crude oil extraction does not produce natural gas as a coproduct of crude oil extraction.

Fugitive emissions as well as raw materials, and energy use are allocated completely to crude oil production for advanced CO₂ injection onshore crude oil extraction.

CRUDE OIL TRANSPORT TO REFINERY

The U.S. is broken up into PADDs in order to ensure that each region or PADD is supplied with enough petroleum for strategic defense reasons. The transportation distances used in this report are regionalized by these PADDs. However, there is no specific ton-mile information available for crude oil transportation per PADD. Therefore, certain assumptions have to be made regarding crude oil transportation as described in the following sections:

Transportation Regionalization

The amount of foreign and domestic crude oil transported into each PADD is estimated from refinery receipts of crude oil which is known for each PADD [8].³⁸ The following tables (Table 103 and Table 104) describe refinery receipt of crude oil for 11 different methods of transport and two different sources, foreign and domestic.

³⁸ Data for 1993 were used because that was the latest year for which information used to calculate transportation distances could be found.

Table 103: Refinery Receipts of Crude Oil by Source and by PADD (1993)

<i>Source</i>	<i>Petroleum Administration for Defense District</i>					
	<i>I</i>	<i>II</i>	<i>III</i>	<i>IV</i>	<i>V</i>	<i>Total U.S.</i>
Total:	(%)	(%)	(%)	(%)	(%)	(%)
Domestic	2.68	56.03	39.37	81.33	90.12	50.41
Foreign	97.32	43.97	60.63	18.67	9.88	49.59
Total:	100	100	100	100	100	100

Table 104: Refinery Receipts of Crude Oil by Method of Transportation and by PADD (1993)

<i>Method</i>	<i>Petroleum Administration for Defense District</i>					
	<i>I</i>	<i>II</i>	<i>III</i>	<i>IV</i>	<i>V</i>	<i>Total U.S.</i>
Pipeline:	(%)	(%)	(%)	(%)	(%)	(%)
Domestic	13.3	96.9	84.4	86.8	38.6	71.9
Foreign	0.17	51.8	22.9	0	0	23.2
Canadian	4.59	48.2	0.31	99.8	18.1	12.5
Tanker:						
Domestic	1.73	0	0.78	0	59.5	20.2
Foreign	90.7	0	75.7	0	70.5	62.4
Barge:						
Domestic	10.7	0.19	11.8	0	0.67	4.57
Foreign	4.57	0	1.12	0	11.4	1.92
Tank Cars:						
Domestic	41.2	0	0.08	0.65	0.21	0.34
Foreign	0	0	0	0.19	0	0
Trucks:						
Domestic	33.1	2.93	2.99	13.1	0.98	2.98
Foreign	0	0	0	0	0	0
Total:						
Domestic	100	100	100	100	100	100
Foreign	100	100	100	100	100	100

Pipeline transportation is broken out for Canadian and other foreign sources. This is done to account for the fact that foreign oil, other than Canadian, must travel via tanker to the United States before it enters a domestic pipeline.³⁹

Transportation Distances

The distances used in this project are based on national average distances. These distances were obtained through the following sources of data and methods of calculation:

³⁹ Transportation of crude oil within foreign countries is limited to pipeline transport. This seems to be a fair estimate considering the small amount of crude oil shipped by alternative methods in the United States. About 15% of all foreign oil (excluding Canada) will travel in a foreign pipeline before being shipped to the United States.

Domestic Tanker and Domestic Barge:

- *Source of Data:* Waterborne Commerce of the United States, Calendar Year 1993, Part 5 - National Summaries. Department of the Army, Corps of Engineers.
- *Calculation Method:* Army report lists tons and ton-miles of crude oil transported by tanker and barge on all U.S. waterways. Data listed are not just for refinery receipts but include all transport (including any transport to storage facilities). Average miles are calculated by dividing total ton-miles traveled by total tons transported. This is done separately for both tanker and barge.

Domestic Pipeline:

- *Source of Data:* Association of Oil Pipelines, using data from Annual Report (Form 6) of oil pipeline companies to the Federal Energy Regulatory Commission. EIA, Petroleum Supply Annual, 1993, Vol. 1.
- *Calculation Method:* Association of Oil Pipelines lists total ton-miles of crude oil carried in domestic pipelines. Petroleum Supply Annual lists refinery receipt of crude oil by PADD by method and source of transportation. Petroleum Supply Annual gives crude oil receipts in barrels which is converted to tons.⁴⁰ Average miles are calculated by dividing total ton-miles of crude oil, carried in domestic pipelines, by tons of crude oil received at refineries via pipeline.

Domestic Rail:

- *Source of Data:* Association of Oil Pipelines, using data from Carload Way Bill Statistics, Report TD-1, Department of Transportation, Federal Railroad Administration, annual, and Freight Commodity Statistics, Association of American Railroads, annual. EIA, Petroleum Supply Annual, 1993, Vol. 1.
- *Calculation Method:* Association of Oil Pipelines lists total ton-miles of crude oil carried by rail in the United States. Petroleum Supply Annual lists refinery receipt of crude oil by PADD by method and source of transportation. Petroleum Supply Annual gives crude oil receipts in barrels which is converted to tons. Average miles are calculated by dividing total ton-miles of crude oil, carried by rail, by tons of crude oil received at refineries via railroad tank cars.

Domestic Truck:

- *Source of Data:* Association of Oil Pipelines, using data from Financial and Operating Statistics, American Trucking Association, Inc. EIA, Petroleum Supply Annual, 1993, Vol. 1.
- *Calculation Method:* Association of Oil Pipelines lists estimated total ton-miles of crude oil transported by motor carriers in the United States. Petroleum Supply Annual lists refinery receipt of crude oil by PADD by method and source of transportation. Petroleum Supply Annual gives crude oil receipts in barrels which is converted to tons. Average miles are calculated by dividing total ton-miles of crude oil, transported by motor carriers, by tons of crude oil received at refineries via truck.

Foreign Pipeline to Coast and Canadian Pipeline to the United States:

- The same value is used that was calculated for Domestic Pipeline.

Foreign Tanker:

- *Source of Data:* Delucchi, M.A., Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity, Vol. 2 Argonne National Laboratory, 1993. EIA, Petroleum Supply Annual, 1994, Vol. 1.
- *Calculation Method:* The Petroleum Supply Annual lists imports of crude oil by country for each PADD (in barrels). PADD I crude oil is assumed to all arrive at New York. PADD II and III oil is assumed to arrive at Houston. (PADD II oil arrives at Houston and then is transported by pipeline, barge, etc. to its final destination). PADD V oil is assumed to arrive at Los Angeles. PADD IV does not receive any foreign oil other than Canada.

⁴⁰ Conversion of crude oil from barrels to tons is done using the conversion factor of 6.62 bbls equals one ton.

Nautical miles between ports of origin and U.S. ports (New York, Houston, and Los Angeles) are given in Delucchi's study, based on information from the Defense Mapping Agency [9]. From this information a weighted average is calculated, for each PADD, by multiplying barrels imported from each country by the distance from that country to the specified U.S. port of entry. These results, in barrel-miles for each PADD, are added together and then divided by the total number of barrels imported to get an average distance traveled by the foreign tankers (in miles).

Average mileage values for all modes of transportation are then converted into kilometers.

Transportation Models

Ecobalance maintains a database of transportation methods and environmental impacts associated with those methods. This database, DEAM™, is utilized to account for the environmental impacts of transporting crude oil from extraction sites to refinery locations.

The following sources of fuel are assumed for each method of transportation:

- Pipelines: Electricity, assume that U.S. pipelines draw from average U.S. power mix. Energy consumption: 0.0184 kWh electricity per ton-mile [10].
- Rail and Trucks: #2 diesel fuel
- Ocean Tankers and Barges: #6 fuel oil

A problem arises with rail and trucks as they require #2 diesel fuel, which is the output of this model. This is handled by iterating the model for diesel fuel. The model was run the first time with surrogate values for production of #2 diesel fuel. Then the new results of the model are taken and inserted back into the model to replace the previously used values for production of #2 diesel fuel. The model is run again with the new values to obtain the final result.

Empty backhauls are taken into account for truck transportation.

The following figure (Figure 92) demonstrates graphically how crude oil transportation is regionalized in this project. Example percentages for mode of transport are given for PADD II to clarify how the information is used.

Energy and Fugitive Emissions from Storage and Handling

In addition to the energy requirements and subsequent emissions from the actual modes of transportation (e.g., truck diesel use and emissions, pipeline electricity requirements, and emissions from electricity production, etc.), there are also energy and emissions due to loading and unloading of the crude oil.

The loading and unloading of crude oil is assumed to require electricity for pumping. The amount of electricity used is based on the electricity required for pipeline transport. Pipelines are assumed to require 5.8×10^{-5} MJ of electricity per 1 kg transported 1 km. For loading and unloading, it is assumed that the distance fuel would be pumped is 50 meters and that the energy required for pumping is linear with distance pumped. Therefore, 2.9×10^{-6} MJ of electricity are required for loading and unloading one kg of fuel.

The emissions associated with loading and unloading trucks and rail cars were based on the following formula [11]:

$$L_L = 12.46 \frac{SPM}{T} \left(1 - \frac{eff}{100}\right)$$

Equation 1: Estimating Emissions from Loading and Unloading Trucks and Rail Cars

Where:

L_L = loading loss in pounds per 1000 gallons

S = saturation factor

P = true vapor pressure of fuel transported (psia)

M = molecular weight of fuel vapors (lb/lb-mole)

T = temperature of the fuel ($^{\circ}R = (^{\circ}F + 460)$)

eff = overall reduction efficiency (%)

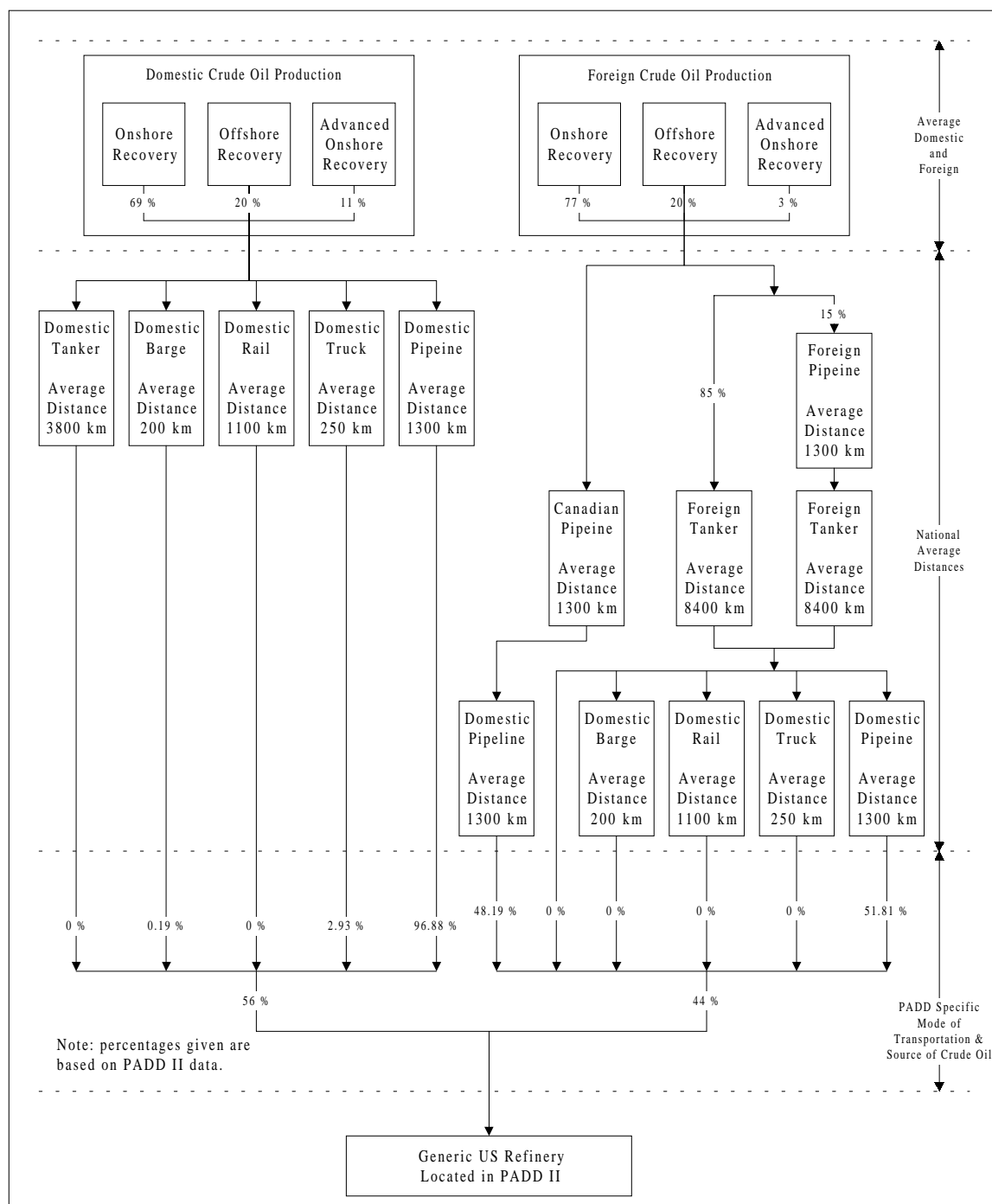


Figure 92: Crude Oil Transportation Modeling

The saturation factor is based on the type of carrier and the mode of operation.⁴¹ For this project an average S value is used that is the straight average of all possible operation modes.

⁴¹ The different types of carriers include normal service and vapor balance service in which the cargo truck retrieves the vapors displaced during product unloading and transports the vapors back to the loading terminal. Modes of operation include submerged and splash loading.

The vapor pressure of the fuel (in this case, crude oil) is estimated at 60°F based on information in AP-42. The M (or molecular weight of the crude oil vapors) is also taken from information in AP-42. The temperature is assumed to be 60°F to match the vapor pressure and molecular weight data.

The reduction efficiency is a measure of how much of the vapors are collected and then subsequently controlled. In this case it is assumed that 70% of the vapors were collected and then 90% of those collected vapors were controlled to yield an overall efficiency of 63%.⁴²

The emissions associated with loading and unloading tankers and barges were based on the following formula [11]:

$$C_L = (C_A + 1.84(0.44P - 0.42) \frac{MG}{T})$$

Equation 2: Estimating Emissions from Loading and Unloading Tankers and Barges

Where:

C_L = total loading loss in pounds per 1000 gallons

C_A = arrival emission factor (lb/1000 gal)

P = true vapor pressure of fuel transported (psia)

M = molecular weight of fuel vapors (lb/lb-mole)

G = vapor growth factor = 1.02 (dimensionless)

T = temperature of the vapors ($^{\circ}R = (^{\circ}F + 460)$)

eff = overall reduction efficiency (%)

The arrival emission factor is based on information in AP-42 and is determined by the condition of the transportation vessel upon arrival. In this project it is assumed to be an uncleaned vessel.⁴³

The vapor pressure of the fuel (in this case, crude oil) is estimated at 60°F based on information in AP-42. The M (or molecular weight of the crude oil vapors) is also taken from information in AP-42. The temperature is assumed to be 60°F to match the vapor pressure and molecular weight data.

In addition to loading and unloading fugitive emissions there are also fugitive emissions associated with transit of the fuel. The emissions associated with truck, train, tanker, and barge transit were based on the following formula [11]:

$$L_T = 0.1PW$$

Equation 3: Estimating Fuel Transit Emissions

Where:

L_T = transit losses in pounds per 1000 gallons per week

P = true vapor pressure of fuel transported (psia)

W = density of the condensed vapors (lb/gal)

The vapor pressure of the fuel (in this case, crude oil) is estimated at 60°F based on information in AP-42. The W (or density of the condensed crude oil vapors) is also taken from information in AP-42. The value obtained for L_T can be converted to pounds per 1000 gal per km based on the speed of the different modes of transportation used. The following conversion factors are computed from average speeds for the different modes of transport:

Tanker - 1 week = 4,317.6 km

Rail - 1 week = 10,752 km

Barge - 1 week = 2,167.2 km

Truck⁴⁴ - 1 week = 5,792 km

Figure 93 represents how the emissions from crude oil transportation are modeled in this project.

⁴² Both the 70% collection efficiency and 90% control efficiency are the low range of values reported in AP-42.

⁴³ Therefore, no ballast emissions are accounted for.

⁴⁴ Assuming the truck is running at 60 mph for 10 hours a day and 6 days a week.

Note that fugitive tank emissions from the storage of crude oil at the oil field are accounted for in crude oil extraction modeling. Also, fugitive tank emissions from the storage of crude oil at the refinery are accounted for in the crude oil refining model.

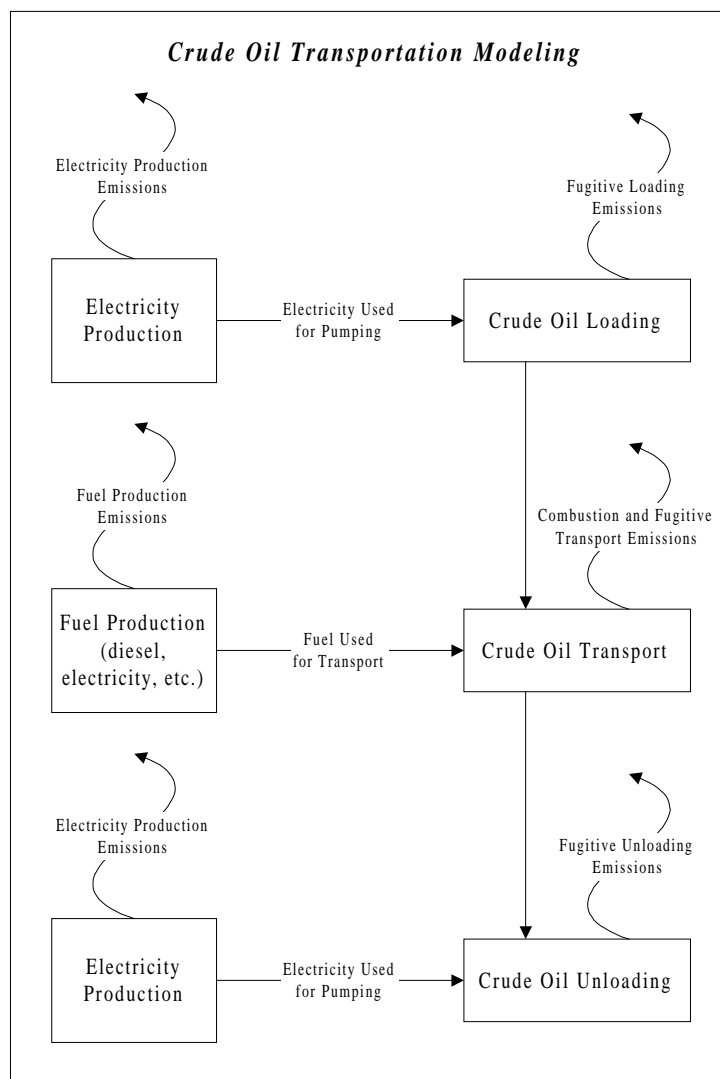


Figure 93: Crude Oil Transportation Modeling

CRUDE OIL REFINING

The modeling of crude oil production and transportation to a refinery have been described in the previous sections. This section of the report describes the system of refining crude oil into petroleum-based products as shown in Figure 94.

The modeling of petroleum refining is based on the U.S. refining averaged performance as opposed to a PADD-specific refinery. Therefore, the size and complexity of different refineries in different PADDs are not taken into account.

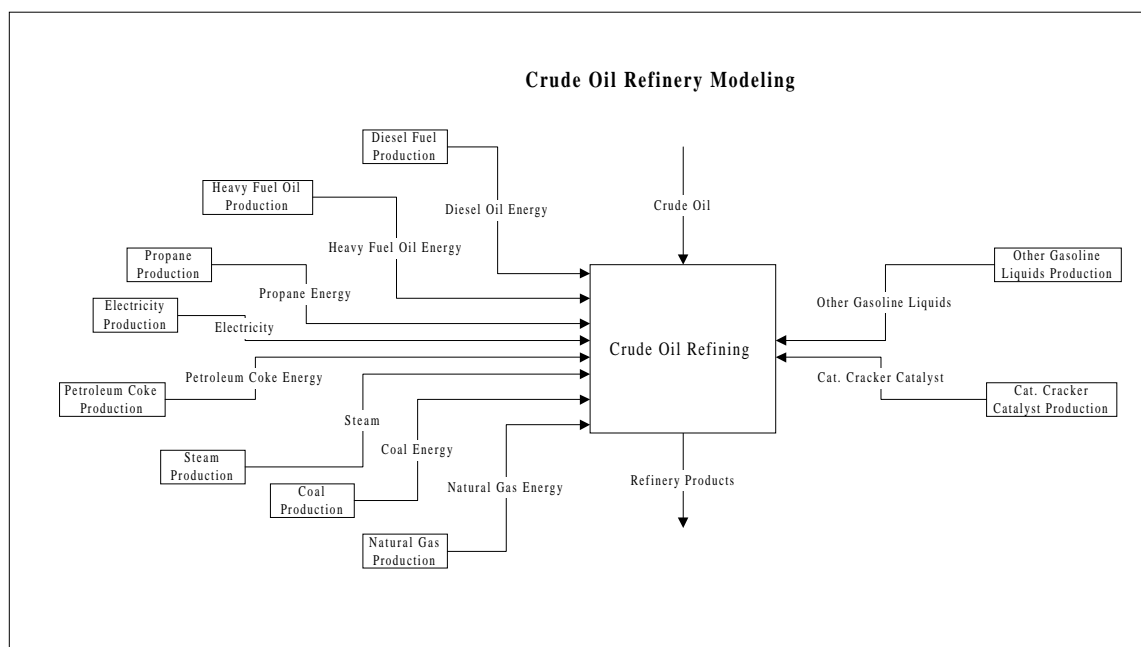


Figure 94: Petroleum Refining System Description

EIA data from the Petroleum Supply Annual 1994, Volume 1 were used to establish the volumetric flows for the U.S. refining industry. A closed mass and energy balance was created from the U.S. 1994 EIA refining data⁴⁵. To accomplish this, the EIA volumetric data were converted to masses using input and product densities obtained from the literature for the streams. The energy flows were estimated from the same densities. Heat rejection to cooling water was based upon published literature values.

Other assumptions included:

- The crude gravity assumed was 32 deg API from Bonner and Moore, refinery Economics Short Course Text, Feb 1994.
- Product densities were estimated for all streams from Bonner and Moore, except coke where the EIA definition of 5 bbl/ton was used.
- The heating value of a fuel oil equivalent of 6 MM Btu/bbl was used for refinery energy consumption data.
- Natural gas was assumed to have 1012 Btu/scf.
- Coal was assumed to be 24 MM Btu/ton
- NBS Misc Pub 97 was used to estimate the heats of all petroleum materials below 50 deg API.
- Gasoline heating value was estimated from ANL/ESD-28 adjusted for HHV for summer RFG.
- Other liquids, oxygenates, and natural gasoline, were assumed to have a gravity equal to gasoline and a heating value typical of oxygenates. Unfinished oils were assumed to be fuel oil.
- Still gas mass was estimated assuming 23,500 Btu/lb for the gas (about 75% methane), using 19350 Btu/lb and 0.887 spg for the fuel oil equivalent barrel.
- The plant heat loss to cooling water was estimated from Gary and Handwerk, Petroleum Refining technology and economics, 3rd Edition, Marcel Dekker, NY, 1994. The authors provide a case study for a 100,000 bbl/day refinery of moderate complexity. The total reported cooling water duty is 1,252 gal/bbl crude fed at 30F temperature rise. Fifty percent of the duty is used for boiler feed water heating.

⁴⁵ Mass and energy balance was computed by Mike Graboski of the Colorado School of Mines.

- It is assumed that plant convective and radiation heat losses are negligible.
- Electricity was charged at 3413 Btu/kwh.

The results of the mass and energy balance were as follows:

The mass balance closed to within 0.5%. Still gas and catalyst coke are burned in the plant and thus do not show up as useful products. The indicated crude used is 105.56% of the products on a fuel oil equivalent basis.

The energy balance closes to within 0.3%. The energy inputs plus recycled still gas and coke amount to about 9.7 % of the energy of the useful products out.

The energy balance suggests that an additional 2.6% is heat losses from the plant in cooling water. Thus the amount of energy consumed per gallon of low-sulfur diesel is 17,292 Btu.

The amount of crude to the refinery (from the EIA report) needs to be increased by 5.56% in the model to cover mass losses in still gas and catalyst coke. This impacts upstream recovery and transportation.

Material Use

For this report, it is assumed that the material required by the crude oil refinery includes the crude oil itself plus other petroleum-based feedstocks, purchased energy inputs and process catalysts, assumed to be catalytic cracking catalyst as shown in Figure 94 above.⁴⁶

The amounts of crude oil and other petroleum based feedstocks required are taken from the total inputs to all U.S. refineries from EIA, Petroleum Supply Annual (1994) as described in the mass balance above.

The EIA report lists the total U.S. refinery inputs of crude oil, other gasoline liquids, and unfinished oils for 1994. The following table (Table 105) lists the amount of materials input to all U.S. refineries.

Table 105: Material Inputs to U.S. Refineries

<i>Flow Name</i>	<i>Units</i>	<i>Value per Year</i>
Crude Oil	kg	6.95×10^{11}
Other Gasoline Liquids	kg	7.90×10^9
Unfinished Oils	kg	2.24×10^{10}

For this project, unfinished oils are added to the total for crude oil input. The LCI results for the production of the other gasoline liquids are from Ecobalance's database and assumed to be produced from natural gas. The amount of crude to the refinery is increased by 5.56% to cover mass losses in still gas and catalyst coke.

The amount of catalytic cracking catalyst required is based on the uncontrolled particulate emissions from the catalytic cracker. It is assumed that all of the particulate produced by the catalytic cracker results from the loss of the catalyst. Therefore, the lost catalyst needs to be made up with additional inputs. Based on U.S. EPA AP-42 data for uncontrolled particulate emissions from catalytic cracking, 0.566 g of catalyst is required per liter of crude oil through the catalytic cracking units. Other catalyst inputs are much smaller than the cracking catalyst.

The production of catalytic cracking catalyst is taken from Ecobalance's database based on a Zeolite catalyst.

Energy/Equipment Use

Petroleum refineries draw most of their energy requirement from the crude oil stream. However, additional energy requirements and process needs are fulfilled through the following inputs (Table 106) as shown in Figure 94 [12] and mass balance above:

⁴⁶ Import of hydrogen is not accounted for in this model. It is assumed that all of the hydrogen used is produced within the refinery. Therefore, the energy required by the refinery accounts for this hydrogen production.

Table 106: Energy Inputs to Petroleum Refineries

<i>Flow Name</i>	<i>Units</i>	<i>Value per Year</i>
Natural Gas	MJ	7.66×10^{11}
Coal	MJ	3.27×10^9
Steam	MJ	3.8×10^{10}
Electricity	MJ elec.	1.43×10^{11}
Propane (C ₃ H ₈ , kg)	MJ	6.21×10^{10}
Diesel Oil (kg)	MJ	3.16×10^9
Heavy Fuel Oil	MJ	6.13×10^{10}
Coke	MJ	1.77×10^{10}
Other	MJ	8.8×10^9

These numbers are based on the total U.S. consumption of fuels at all refineries. The production of propane, diesel oil, heavy fuel oil, and coke could actually happen inside the refinery from the crude oil stream. However, EIA reports them as if they are imported. This approach accounts for the energy and emissions needed to produce the fuels. In addition to the fuels listed in the table above, the refinery also draws energy directly from the crude oil stream as shown in Table 107.

Table 107: Refinery Energy Sources from the Crude Oil Stream

<i>Flow Name</i>	<i>Units</i>	<i>Value per Year</i>
Still Gas	MJ	1.52×10^{12}
Catalyst Coke	MJ	5.14×10^{11}

The production of these fuels are assumed to be accounted for in the emissions and energy requirements of the refinery modeled here.

Process Emissions

Emissions from crude oil refining include air emissions, water effluents, and solid waste. The following sections describe how each of these is modeled from crude oil refining.

Air Emissions

Air emissions from crude oil refining are assumed to come from three sources:

- 1) Fuel Combustion
- 2) Process Emissions
- 3) Fugitive Emissions

Fuel combustion emissions are based on the amount and types of fuels consumed and emission factors for specific combustion devices. All the fuels used in the refinery are assumed to be combusted in industrial boilers.⁴⁷

The emissions for electricity production are based on Ecobalance's database DEAMTM for the standard U.S. electricity grid. Emissions for purchased steam production are based on Ecobalance's database DEAMTM for the production of steam from natural gas.

⁴⁷ Some of the natural gas imported to the refinery is used to produce hydrogen. Therefore, assuming the emissions from combustion of all the natural gas in an industrial boiler may overestimate the emissions of the refinery somewhat. This will only affect the combustion-related emissions of NO_x, CO, PM, and hydrocarbons, as hydrogen production still produces carbon dioxide.

Process emissions for a petroleum refinery are based on emission factors published in EPA AP-42. The emission factors for petroleum refining processes are shown in Table 108:

Table 108: Petroleum Refining Process Emissions

<i>Process</i>	<i>Emission Factors</i>					
	<i>Particulate</i>	<i>SO₂</i>	<i>CO</i>	<i>Non-Methane Hydrocarbons</i>	<i>NO₂</i>	<i>CO₂</i>
Catalytic cracking (g/L crackers feed)	0.052	0.79	--	--	0.11	40.7
Fluid coking (g/L cokers feed)	1.5	--	--	--	--	--
Vapor recovery/flare (g/L refinery feed)	--	0.077	0.012	0.002	0.054	--
Sulfur recovery (g/kg sulfur produced)	--	29	--	--	--	--

Some assumptions have been made to arrive at the numbers shown in the previous table. They are:

- Catalytic cracking input is assumed to be a 80/20 split between Fluid Catalytic Cracking (FCC) and moving bed catalytic cracking units. All catalytic cracking units are assumed to have a CO boiler and electrostatic precipitator installed. Carbon monoxide and hydrocarbons burned in CO boiler are assumed to be converted to CO₂.
- A vapor recovery and flaring system is assumed to be installed to control the emissions from the blowdown system. Blowdown hydrocarbon emissions are assumed to be converted to CO₂. The amount of hydrocarbons produced is based on the emissions from one refinery in Yorktown, Virginia [13]. Based on the Yorktown study, 1.86 g of hydrocarbon emissions are produced per kg of crude oil into the refinery. If a 75% carbon content is assumed for the hydrocarbon emissions, then 5.11 g of CO₂ is produced per kg of crude oil into the refinery.
- Emissions from the vacuum distillation column are assumed to be negligible.
- Claus recovery plant is assumed to recover 98.6% of sulfur in tail gas and have controlled emissions. This is the highest rate listed by U.S. EPA AP-42 for sulfur recovery. This corresponds to an emission factor of 29 g of SO_x per kg of sulfur produced.

Flows associated with the different petroleum refinery processes are taken from EIA, Petroleum Supply Annual (1994) and are shown in Table 109:

Table 109: Refinery Process Flows

<i>Process</i>	<i>Associated flow</i>
Catalytic cracking	2.8 x 10 ¹¹ (L feed/yr)
Fluid coking	8.9 x 10 ¹⁰ (L feed/yr)
Vapor recovery/flare	8.4 x 10 ¹¹ (L refinery feed/yr)
Sulfur recovery	8.2 x 10 ⁹ (kg sulfur produced/yr)

Fugitive emissions for a petroleum refinery are based on the emissions from one refinery in Yorktown, Virginia [13]. Based on the Yorktown study, 0.97 g of hydrocarbon emissions are produced per kg of crude oil into the refinery.

Water Effluents

Water effluents from the refinery are based on the total amount of wastewater produced and the composition of the wastewater. Wastewater volume produced by the refinery is calculated using Table 110 [14]:

Table 110: Wastewater Production in Crude Oil Refineries

<i>Wastewater Source</i>	<i>Emission Factor (gal/bbl)</i>	<i>Crude oil (bbl/yr)</i>	<i>Crude oil (gal/yr)</i>	<i>Crude oil (liter/yr)</i>
Crude Oil Storage, Desalting & Atmospheric Distillation	4.4	5.06×10^9	2.23×10^{10}	8.43×10^{10}
Gases Water Wash	3.3	5.06×10^9	1.67×10^{10}	6.32×10^{10}
Vacuum Distillation	7.3	2.53×10^9	1.85×10^{10}	6.99×10^{10}
Light Hydrocarbon Hydrodesulfurization	1.9	9.49×10^8	1.80×10^9	6.82×10^9
Middle Distillates Hydrotreating	5.2	3.58×10^9	1.86×10^{10}	7.04×10^{10}
Catalytic Cracking	9.5	1.77×10^9	1.68×10^{10}	6.37×10^{10}
Hydrocracking	4.5	3.67×10^8	1.65×10^9	6.25×10^9
Coking	6.4	5.62×10^8	3.60×10^9	1.36×10^{10}

Wastewater composition in milligram per liter (mg/liter) is given in Table 111 [15]:

Table 111: Crude Oil Refinery Wastewater Composition

<i>Pollutant</i>	<i>Concentration (mg/liter)</i>
BOD	1,300
COD	11,000
TOC	9,200
TSS	5,900
Ammonia Nitrogen	190
Phenols	25
Sulfides	--
Oil and Grease	500
Total Chromium	16

Solid Waste

Solid waste is computed from factors given in a recent study of refinery generation of solid waste [16]. The study gave totals for hazardous and nonhazardous wastes as shown in Table 112.

Table 112: Solid Waste Produced from Crude Oil Refining

<i>Type of Waste</i>	<i>Amount of Waste (kg/yr)</i>
Hazardous	1.6×10^9
Nonhazardous	2.6×10^9

Petroleum-Based Products Production

Petroleum refineries produce a number of different products from the amount of crude oil that they receive. However, typically a study is only concerned with one specific product, (e.g., gasoline). Therefore, there needs to be a method of allocating total refinery energy use and total refinery emissions to only the production of one product. Additional complexity is introduced by the fact that the refinery product mix is variable, both among refineries and even with time for a given integrated refinery.

The simplest allocation procedure would be to allocate total refinery releases (and consumption) among the products on a mass output basis. The following table (Table 113) outlines how this would be done, based on the output of a generic U.S. refinery:

Table 113: Production of an Average U.S. Refinery

<i>Refinery Flow</i>	<i>Mass (kg/yr)</i>	<i>Mass (%)</i>
Diesel Oil (< 0.05% Sulfur, kg):	9.30×10^{10}	12.8%
Diesel Oil (> 0.05% Sulfur, kg):	6.76×10^{10}	9.33%
Gasoline:	3.08×10^{11}	42.5%
Heavy Fuel Oil:	4.52×10^{10}	6.24%
Jet Fuel (kg):	6.53×10^{10}	9.01%
Kerosene (kg):	2.74×10^9	0.38%
Misc. Refinery Products (U.S., kg):	2.19×10^9	0.30%
Petroleum Coke (kg):	4.12×10^{10}	5.69%
LP Gas:	1.92×10^{10}	2.66%
Asphalt (kg):	2.72×10^{10}	3.75%
Lubricants (kg):	8.87×10^9	1.22%
Petrochemical Feedstocks (kg):	4.04×10^{10}	5.57%
Petroleum Waxes (kg):	9.71×10^8	0.13%
Naphthas (kg):	2.35×10^9	0.33%
Total:	7.24×10^{11}	

However, this would result in the same LCI profile for every kg of refinery product regardless of its characteristics (e.g., one kg of diesel fuel would have the same profile as one kg of gasoline).

An objection to the mass allocation approach, which is based on output share, is that a kg of different refinery products requires different amounts of processing, thus requiring different amounts of energy input and leading to different amounts of releases.

An alternate allocation method would be one based on the share of the total process energy required to produce the refinery product.

This method of allocating refinery flows based on process energy requirements is outlined in the following steps:

- Calculate the percentage of total refinery energy used by each different process within the refinery.
- Calculate a specific refinery product's share of each process' energy consumption.
- Multiply the two results in order to get the percentage of total refinery energy allocated to a single refinery product production for each process. Adding the results of each process gives the percentage of **total** refinery energy allocated to a **total** single refinery product.
- Allocate emissions and energy use based on the percentage of total refinery energy allocated to a **total** single refinery product. (from step 3 above)

Many different studies have been done in the past in order to estimate total refinery energy allocation to the different processes within a refinery [1]. These studies, however, were predominantly done in the late 1970s and early 1980s and their relevance to today's refinery processes is not fully known. This is complicated by the fact that refinery energy requirements are considered proprietary information so it is difficult to confirm the past studies findings.

For this project, an additional study done by White et al. [17]⁴⁸ will be used with two studies listed by Delucchi [2] to help estimate refinery process energy allocation. This study may not be completely applicable, for the reasons outlined above, but it was found to be the most comprehensive and descriptive of what had been done.

The three refinery models list energy consumption for different refinery processes. This information is used to calculate the percentage of total refinery energy used by each different process within the refinery.⁴⁹ The following table (Table 114) lists the results:

Table 114: Fraction of Total Refinery Energy Used by Each Process

<i>Refinery Process</i>	<i>Fraction of Total Refinery Energy</i>			
	<i>Lawrence</i>	<i>Haynes</i>	<i>White et al.</i>	<i>Average</i>
Crude distillation	0.276	0.364	0.266	0.302
Catalytic cracking	0.314	0.065	0.124	0.168
Thermal cracking	0	0.033	0	0.011
Hydrocracking	0	0.044	0	0.015
Desulfurization	0.02	0	0.046	0.022
Hydrotreating	0	0.085	0.068	0.051
Alkylation	0.065	0.069	0.040	0.058
Reforming	0.191	0.225	0.140	0.185
Coking	0.038	0.032	0.077	0.049
Visbreaking	0	0.007	0	0.002
Propylene concentration	0.05	0	0	0.017
Isomerization	0.042	0.002	0	0.015
Hydrogen	0	0.025	0.070	0.032
Depentanizer	0	0	0.0167	0.006
Naphtha Pretreater	0	0	0.054	0.018
Saturated gas plant	0	0	0.035	0.012
Unsaturated gas plant	0	0	0.064	0.021
Finishing and other	0.003	0.055	0	0.019
Total:	0.999	1.006	1.000	1.002

For this study the average values for fraction of total refinery energy used by each process will be used. Averaging the values from the three studies is thought to help compensate for the differences in refinery configurations and size.

⁴⁸ The authors were, at the time of the study, all members of Mobil Research and Development Corp., Princeton and Paulsboro, NJ.

⁴⁹ Note: The White et al. refinery does not take into account increased energy requirements for producing low-sulfur diesel fuel. Therefore, energy values from White et al. for hydrogen manufacture and hydrodesulfurizer have been increased to account for removal of more sulfur. The increase is based on assuming that the energy consumption given in White et al. represented removal of 1.25% of the sulfur in the incoming crude (Crude oil = 1.5% sulfur, Diesel fuel = 0.25% sulfur). Then assume a linear increase in energy consumption based on removing 1.45% of the sulfur (low sulfur diesel fuel = 0.05% sulfur).

An individual refinery product's share of each process' energy consumption can be calculated from information provided in a recent DOE study [1] and information on refinery production [12].

Table 115: Fraction of Refinery Process Energy Used by Types of Refinery Products

<i>Refinery Process</i>	<i>Fraction of Process Energy</i>			
	<i>Gasoline</i>	<i>Distillate</i>	<i>Residual</i>	<i>Other</i>
Crude distillation	0.454	0.302	0.07	0.174
Catalytic cracking	0.55	0.365	0.085	
Thermal cracking	0.454	0.302	0.07	0.174
Hydrocracking	0.541	0.359		0.1
Desulfurization	0.454	0.302	0.07	0.174
Hydrotreating	0.541	0.359		0.1
Alkylation	1			
Reforming	1			
Coking	0.541	0.359		0.1
Visbreaking		1		
Propylene concentration				1
Isomerization	1			
Hydrogen	0.541	0.359		0.1
Depentanizer	1			
Naphtha Pretreater	0.994			0.006
Saturated gas plant	0.89			0.11
Unsaturated gas plant	0.89			0.11
Finishing and other	0.454	0.302	0.07	0.174

The DOE study allocates energy use in different refinery process areas to gasoline, total distillates and residual fuel in proportion to process energy output of the different products.⁵⁰ Table 115 shows the results. The values in this table can be multiplied by the average fraction of total refinery energy used by each process to determine the total process energy required to produce each of the four different types of refinery fuels shown above. The results of this are shown in Table 116.

An example of how this is used to determine the allocation percentage for diesel fuel is shown as follows:

The results of Table 116 state that 22.3% of the total refinery energy is needed to produce distillate fuels.

However, total distillates, as described in the DOE study, include diesel fuel, jet fuel, kerosene, and residual fuel. The fraction of total distillates taken up by diesel fuel is shown in Table 117.

It is found that diesel fuel makes up 59% of total distillate production on a mass basis.

This result can be combined with the energy fraction needed to produce total distillates to give diesel fuel's share of refinery energy consumption as follows:

$$22.3\% \times 59\% = 13.2\%$$

The same method is used to calculate the allocation percentage for the other refinery products used in this study. For gasoline an allocation of 64.3% is used directly from Table 32.

⁵⁰ Allocation is based on the energy output of the three different products from each of the different refinery processes. For example alkylation, reforming, and isomerization produce only high-octane gasoline components. Therefore, the process energy associated with alkylation, reforming, and isomerization is allocated entirely to gasoline production.

Table 116: Fraction of Total Refinery Energy Used by Category of Refined Product

<i>Refinery Process</i>	<i>Fraction of Total Refinery Energy</i>			
	<i>Gasoline</i>	<i>Distillate</i>	<i>Residual</i>	<i>Other</i>
Crude distillation	0.14	0.091	0.021	0.053
Catalytic cracking	0.09	0.061	0.014	0
Thermal cracking	0.0050	0.0033	0.0008	0.0019
Hydrocracking	0.008	0.0053	0	0.0015
Desulfurization	0.0100	0.0066	0.00154	0.0038
Hydrotreating	0.028	0.018	0	0.0051
Alkylation	0.058	0	0	0
Reforming	0.19	0	0	0
Coking	0.026	0.018	0	0.0049
Visbreaking	0	0.0023	0	0
Propylene concentration	0	0	0	0.0167
Isomerization	0.0147	0	0	0
Hydrogen	0.0171	0.0113	0	0.0032
Depentanizer	0.0056	0.0000	0	0.0000
Naphtha Pretreater	0.0178	0.0000	0	0.0001
Saturated gas plant	0.0105	0.0000	0	0.0013
Unsaturated gas plant	0.0189	0.0000	0	0.0023
Finishing and other	0.009	0.0058	0.0014	0.0034
Total:	0.6429	0.2230	0.0390	0.0967

Table 117: Diesel Fuel's Share of Total Distillates

<i>Distillates</i>	<i>Mass (kg/yr)</i>	<i>Mass (%)</i>
Diesel Fuel:	1.61×10^{11}	59%
Heavy Fuel Oil:	4.52×10^{10}	17%
Jet Fuel (kg):	6.53×10^{10}	24%
Kerosene (kg):	2.74×10^9	1%
Total:	2.74×10^{11}	

PETROLEUM PRODUCTS TRANSPORT

The transport modeling of petroleum products from the refinery to a distribution center is shown in Figure 15.

It is assumed that a fraction of refinery products is shipped to local distributors an average distance of 100 miles. The remaining fraction is shipped via pipeline to a tank farm where it is in turn shipped by truck 100 miles to a distributor.

The fraction of refinery product shipped via pipeline is based on Association of Oil Pipelines, using data from Annual Report (Form 6) of oil pipeline companies to the Federal Energy Regulatory Commission. The report lists the percentage of total finished petroleum products that is shipped by pipelines, water carriers, motor carriers, and railroads. The report states that 59% of the finished petroleum products are shipped via pipeline. The remaining 41% is assumed to be transported by truck.

The Association of Oil Pipelines report also lists total ton-miles of finished petroleum products carried in domestic pipelines. The total amount of petroleum products produced in the United States is also known. It is assumed that 59% of these petroleum products are shipped via pipeline. Average pipeline transportation miles are calculated by dividing total ton-miles of petroleum products, carried in domestic pipelines, by tons of petroleum products shipped via pipeline. The result is 595 miles of pipeline transport.

The transportation models from DEAM™ are used to model energy requirements and emissions from the two types of transportation.

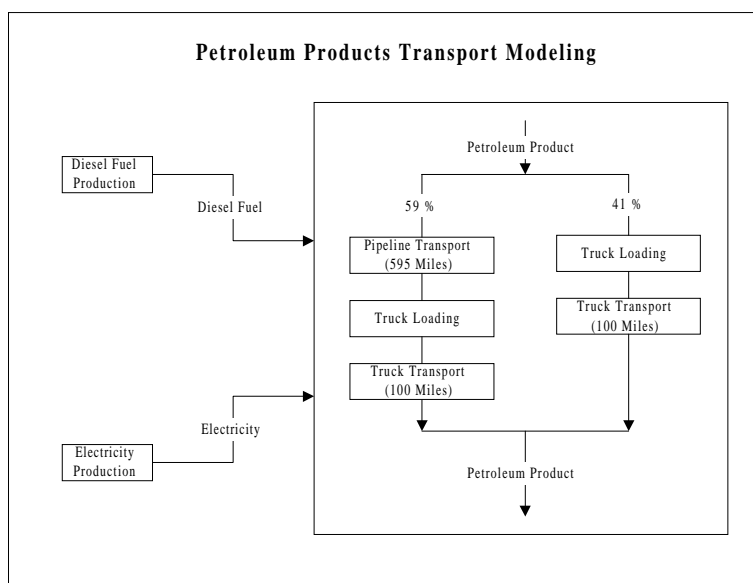


Figure 95: Petroleum Products Transportation Modeling

APPENDIX E: OXYGENATE OVERVIEW

OXYGENATES/GASOLINE OCTANE ENHANCERS

In November 1990, the U.S. Government passed the Clean Air Act Amendments (CAAA). One of the new requirements was for gasolines sold in ambient-air-quality nonattainment areas to contain a minimum amount of oxygen. The U.S. consumption of various oxygenates/gasoline octane enhancers—before and after CAAA passage—is shown in Table 118 [1]. As can be seen, MTBE and ethanol/ETBE are the most widely used oxygenates.

Table 118: U.S. Consumption of Oxygenates/Gasoline Octane Enhancers

<i>Year</i>	<i>MTBE</i>	<i>Ethanol</i>	<i>TAME/ETBE⁵¹</i>	<i>Methanol</i>	<i>Lead Alkyls</i>
	(thousand barrels per day)	(thousand barrels per day)	(thousand barrels per day)	(thousand barrels per day)	(millions of pound per year)
1985	32.4	40	0	6.9	85
1988	74.3	55	0	0	6
1992	113.2	73	3	0	negligible
1995	221	84	20	0	negligible
1997	261	83	17	0	0
2002 (estimate)	265–285	95–100	21–24	0	0
	(thousands of metric tons per year)				
1985	1,395	1,847	0	317	39
1988	3,192	2,540	0	0	3
1992	4,866	3,324	134	0	negligible
1995	9,504	3,878	890	0	negligible
1997	11,245	3,832	756	0	0
2002 (estimate)	11,395–12,255	4,384–4,615	935–1,070	0	0

MTBE

MTBE is easily made by the selective reaction of isobutylene and methanol over an acidic ion-exchange resin catalyst, in the liquid phase. The resin typically consists of sulfonated styrene cross-linked with divinylbenzene. Reaction conditions are usually mild, with temperatures ranging from 30°C to 100°C and pressures between 7 and 14 atmospheres (100–200 psig). For MTBE to be economically competitive as an octane enhancer in gasoline, a low-cost isobutylene source is necessary.

Prior to the 1990 revision of the Clean Air Act, MTBE sold as an octane enhancer for gasoline. Its market value has, therefore, been closely tied to the industry's cost of gasoline and octane. To reflect its higher-than-gasoline octane, it is sold at a price higher than gasoline, usually in the range of 120% to 160% of gasoline. For 1997, the MTBE demand for the United States was about 11 million metric tons per year (Table 118). Table 118 does not report the demand for 1996. Using another source, the 1996 MTBE demand for the United States was estimated at 7.8 million metric tons per year (180,000 barrels per day), whereas the total estimated oxygenate demand for the United States was 16 million metric tons per year (373,000 barrels per day) of MTBE equivalents [2]. This MTBE estimate is lower than that can be interpolated for 1996 from Table 118. Nonetheless, MTBE outstrips the other oxygenates/octane enhancers in consumption.

⁵¹ TAME: tertiary-amyl methyl ether

ETHANOL

Ethanol is commonly used as an oxygenate in several nonattainment areas. Most of the ethanol is produced via fermentation using corn as a preferred raw material. The current production of corn-derived ethanol is in the range of 1.4–1.5 billion gallons (~5.5 billion liters) per year, most of which is used to formulate a 10% blend with gasoline.

ETBE

Ethanol, like methanol, reacts with dialkylated olefins such as isobutylene and isoamylene to produce ethers that can be used as octane enhancers in gasoline. ETBE is produced by the reaction of ethanol with isobutylene in the presence of an acidic ion-exchange resin catalyst. The process is similar to that used for the production of MTBE, however, the process conditions and the catalysts are selected to optimize the conversion of the reactive olefins with ethyl alcohol. The current production of ETBE in the United States is fairly modest.

APPENDIX F: PROJECT MANAGEMENT AND REVIEW

PROJECT MANAGEMENT

The study partners established a steering committee, made up of representatives from state agencies, NREL, and project consultants to direct the LCA. NREL (Kiran Kadam) was responsible for the overall project management and execution.

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The steering committee membership is shown below.

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PROJECT REVIEW

The project was conducted in such a manner as to allow feedback from the stakeholders at various stages of the analysis (see Appendix G for the stakeholder list). The Scoping Document was sent to the stakeholders, and an open meeting was conducted in Sacramento (October 1997) to discuss scoping options and decisions. The Data Summary Document (containing data to be used in the analysis) was sent to the stakeholders for comment in April 1998. Stakeholder comments were incorporated into the final Scoping and Data Summary documents. The Final Report (which contains the LCA results, as well as the scoping decisions and data summary) was reviewed by a panel of experts in various fields before publication.

Review Committee

The steering committee assembled an expert Review Committee to review the Final Report; the Committee membership is shown below.

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APPENDIX H: RESPONSES TO REVIEW COMMITTEE COMMENTS

A key component of this project was the involvement of stakeholders and the review committee during project development and execution (Appendices F and G list the stakeholder and review committee members, respectively). Feedback was provided by stakeholders and reviewers at three stages of the project: a stakeholder meeting was held after the release of the initial scoping document, stakeholder comments were received on the initial data-summary document, and the review committee provided comments on the draft final report. Comments on the scoping and data-summary documents were incorporated into the final draft. This appendix lists the comments and suggestions of the review committee on the draft final report that were not directly accepted or deemed relevant by the authors and provides replies to the same.

1) What about the issue of groundwater contamination by MTBE?

The modeling of the fate of MTBE in groundwater can be considered an impact rather than an emission. A number of factors affect the leaching of MTBE into groundwater (e.g., the porosity of the soil, the location of the leak), which this model cannot take into consideration. No information was available on the water emissions of MTBE during the blending, transportation and storage stages, so no net MTBE water emissions were provided.

2) What are the temporal issues related to this study? What about the rice straw burning system or the fact that a tree used to make ethanol may not burn until 50 years from now?

LCA does not take into account the period over which the emissions occur. The use of an early-next-decade scenario was to define the technology that would be available for such a conversion of biomass to ethanol. Even if one scenario has lower overall emissions, these emissions may occur over a very short period or during high ozone concentration days where their impact would be greater.

3) What about other uses for the biomass sources? Soil incorporation for rice straw or making plywood out of the forest residue?

There are a lot of other options for the disposal of biomass other than burning or conversion to ethanol. However, this study only focused on the current situation, which is assumed to be burning, and one scenario in which biomass was converted to ethanol. The models developed and the information collected for this study could, however, be used to compare other options as part of future studies.

4) What about the economic feasibility of some of these choices? For example, is chaparral really a good biomass source?

The study was developed based on the reduction of rice-straw burning in California. Forest residue is also considered to be a large source of combustion emissions. Both of those feedstocks were assumed to be economically viable for production of ethanol, and there is currently some interest in developing commercial ethanol plants in California based on these feedstocks. Chaparral was similar to both of these feedstocks in that burning emissions were a significant concern. Hence, it was included in the study. However, not much work had been done to study chaparral or determine the economics of its use as an ethanol feedstock. Chaparral is decidedly a less attractive feedstock for ethanol production than rice straw or forest residue. Nonetheless, the boundary choices were considered to be technically feasible, even if they may not be economically feasible at this point. To reiterate, chaparral's inclusion was motivated mainly by its similarity to rice straw and forest residue in terms of burning related emissions.

5) Why are emissions from gas storage tanks considered negligible?

The assumption was made that the emissions for blending would be small relative to the net emissions, and also that the two scenarios would have similar emissions thus offsetting each other.

6) Is the modeling of chaparral as “cutting and piling” prior to burning really accurate? Isn't standing fuel used for areas away from dwellings?

Chaparral use was based on material that is close to residential areas. The reason for this was that homeowners or state and local agencies might possibly be interested in removing the brush as a fire prevention tactic.

7) What about the use of COD and BOD in eutrophication potential?

COD and BOD are a result of water effluents of organic matter, which are assumed to contribute to the growth of plants and algae, which results in eutrophication. The flows selected for inclusion into a eutrophication impact category were based on work done by the Centre of Environmental Science at Leiden University ("Environmental Life Cycle Assessment of Products - Guide and Backgrounds," October 1992, Leiden University, The Netherlands).

8) Why isn't the allocation of co-products done by economic value rather than by mass?

The use of economic value is a possible way of allocating emissions and energy use of a process over multiple products. In this way the use of economic value to allocate between corn steeped liqueur (CSL) and other corn products could result in lower burdens for the CSL than the use of mass allocation. This is due to the low economic value of the CSL compared to the other products. Different allocation approaches for CSL could affect the overall results because the upstream water effluents of CSL production are significant in the life cycle. However, the economic value of products is dependent on price, which is variable depending on the time and location resulting in uncertain life-cycle results. Also, allocating according to economic value could unevenly distribute emissions to products with a greater value even if they actually require less processing. The mass of a product does not necessarily correspond to its emissions or energy use but it was felt to be a better representation than the price.

9) Why is the construction of capital goods not included?

It was a scoping decision based on the fact that capital equipment burdens are often found to be negligible in the overall LCI.

10) How is the benefit of electricity offset being taken into consideration?

During ethanol production, lignin residue is used as a fuel to provide steam and electricity for the process. For some scenarios excess electricity is produced. This electricity is assumed to be sold to the grid and thus replace the production of an equivalent amount of electricity. The emissions for producing a given quantity of electricity from the California grid are subtracted from the ethanol production step. This could result in net negative emissions.

11) Why is only 15% of the MTBE being offset?

The baseline scenarios are restricted only to the production of MTBE within California due to limited isobutylene availability. Since 15% of the total MTBE demand is produced in California, the baseline scenarios are only replacing this amount. Factors such as size of the ethanol plant and transportation distances are based on this assumption. This means that the transport associated with the production of the other 85% of the MTBE that is produced out of state is ignored. A sensitivity analysis was performed which includes this additional 85%. A sensitivity analysis was also performed on using ethanol directly as a reformulated fuel additive. This E10 scenario would be accurate for the entire oxygenate market because it is not dependent on isobutylene availability.

12) What about the issue of land impacts associated with the management of chaparral? How are they quantified?

Land impacts were not quantified because they cannot be considered an 'emission' from collection. They are more relevant to impact assessment, which we limited in this study to more global impact categories.

13) Why aren't other impact categories, such as human health, being used in the analysis?

Again, the impacts were limited to global categories. Collection of data for site- or temporal-specific impacts was beyond the scope of the study.

14) How has the Ecobalance database been checked for quality?

All of the data used in the model have undergone a peer review as part of this project to confirm the quality and representativeness of the data. Also, Ecobalance's models have been reviewed as part of their use in various projects. For example, the petroleum processing model was developed in a joint project with the USDA and USDOE and was validated by reviewers at that time. The electricity model has also been reviewed and validated by various industry representatives.

15) Is soil erosion included in the impacts for natural resource depletion?

The current impact values are relative to the depletion of global reserves. In the current impact assessment model, soil is not considered a natural resource, and soil erosion is not included in the natural resource depletion index. Moreover, it is difficult to quantify soil reserves, which are very location sensitive.

16) How is the nitrogen in straw and other biomass sources accounted for?

The effects of the nitrogen present in the biomass on air emissions and water effluents for ethanol production are assumed to be negligible.

17) What about a discussion of the economic implications of the model's assumptions?

This study focused on environmental impacts and not on economics; however, the economic and technical feasibility of the options was considered in devising scenarios. The technology employed in the project was assumed to be representative of the early next decade. The process performance parameters were based on the best estimates available. The actual economics would depend on such factors as feedstock cost, debt/equity ratio, and government subsidies, the discussion of which is outside the scope of this study.

18) What about alternative uses for the ligneous matter by-product, such as boiler fuel or soil nutrients?

Other uses for the lignin were not considered, although many may exist. The use of the lignin for cogeneration was assumed to be the most likely use for the fuel. Any use has to have a large market because once a few plants are in operation small specialty markets would be swamped.

19) Currently the system boundaries are set so that the burning option of biomass disposal cannot be directly compared to other disposal options not considered here. Why was this done?

There were two functional units considered in this project, the disposal of biomass and the production and use of fuel oxygenate. The system boundaries were not only set to compare biomass burning with other disposal options but more to compare the current situation of biomass disposal and fuel oxygenate production/use to a future scenario in which both were performed simultaneously. The resultant system boundaries reflect the choice of "conversion to fuel oxygenates" as the other disposal option. This specificity of system boundaries ensues from the authors' motive to facilitate an explicit comparison of the current situation and future situations encompassing both biomass burning and fuel oxygenate use. A necessary outcome is that the study as modeled cannot be used to compare biomass burning directly with another disposal option. However, the database developed here will still be useful in conducting such a comparison.

APPENDIX I: REFERENCES

SECTION 1: PROJECT OVERVIEW – REFERENCES

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3. Wang M., C. Saricks, and D. Santini, *Fuel-Cycle Fossil Energy Use and Greenhouse Gas Emissions of Corn Ethanol*, paper presented at the 8th Bio-Energy Conference, Madison, WI, October 5-8, 1998.
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SECTION 2: LIFE CYCLE ASSESSMENT PRINCIPLES – REFERENCES

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REPORT DOCUMENTATION PAGE			Form Approved OMB NO. 0704-0188	
Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Washington Headquarters Services, Directorate for Information Operations and Reports, 1215 Jefferson Davis Highway, Suite 1204, Arlington, VA 22202-4302, and to the Office of Management and Budget, Paperwork Reduction Project (0704-0188), Washington, DC 20503.				
1. AGENCY USE ONLY (Leave blank)	2. REPORT DATE May 1999	3. REPORT TYPE AND DATES COVERED Technical Report		
4. TITLE AND SUBTITLE Environmental Life Cycle Implications of Fuel Oxygenate Production from California Biomass			5. FUNDING NUMBERS WG900101	
6. AUTHOR(S) K.L. Kadam, V.J. Camobreco, B.E. Glazebrook, L.H. Forrest, W.A. Jacobson, D.C. Simeroth, W..J. Blackburn, K.C. Nehoda				
7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES) National Renewable Energy Laboratory, 1617 Cole Boulevard, Golden, CO 80401-3393 Ecobalance, Inc., 15204 Omega Dr., Rockville, MD 20850 TSS Consultants, 2890 Kilgore Road, Rancho Cordova, CA 95670 California Air Resources Board, 2020 L St., Sacramento, CA 95814 California Energy Commission, 1516 9th St., Sacramento, CA 95814 California Department of Forestry and Fire Protection, 1416 9th St., Sacramento, CA 94244			8. PERFORMING ORGANIZATION REPORT NUMBER	
9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES) National Renewable Energy Laboratory 1617 Cole Boulevard Golden, CO 80401-3393			10. SPONSORING/MONITORING AGENCY REPORT NUMBER NREL/TP-580-25688	
11. SUPPLEMENTARY NOTES				
12a. DISTRIBUTION/AVAILABILITY STATEMENT National Technical Information Service U.S. Department of Commerce 5285 Port Royal Road Springfield, VA 22161			12b. DISTRIBUTION CODE	
13. ABSTRACT (<i>Maximum 200 words</i>) Historically, more than 90% of the excess agricultural residue produced in California (approximately 10 million dry metric tons per year) has been disposed through open-field burning. Concerns about air quality have prompted federal, state, and local air quality agencies to tighten regulations related to this burning and to look at disposal alternatives. One use of this biomass is as an oxygenated fuel. This report focuses on quantifying and comparing the comprehensive environmental flows over the life cycles of two disposal scenarios: (1) burning the biomass, plus producing and using MTBE; and (2) converting and using ETBE.				
14. SUBJECT TERMS ETBE, MTBE, biomass, life cycle, bioethanol, open burning			15. NUMBER OF PAGES 204	
			16. PRICE CODE	
17. SECURITY CLASSIFICATION OF REPORT	18. SECURITY CLASSIFICATION OF THIS PAGE	19. SECURITY CLASSIFICATION OF ABSTRACT	20. LIMITATION OF ABSTRACT	